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Electric Utility Steam Generating Units

Background Information for Proposed NO_x Emission Standards

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Revised Standards of Performance for the control of emissions of particulate matter and sulfur dioxide from electric utility steam generating units are also being proposed. These standards are supported in separate Background Information documents, numbered EPA-450/2-78-006a for particulates and EPA-450/2-78-007a for sulfur dioxide.

16. Abstract

Revised Standards of Performance for the control of emissions of nitrogen oxides from electric utility power plants are being proposed under the authority of section 111 of the Clean Air Act. These standards would apply only to electric utility steam generating units capable of combusting more than 73 MW heat input (250 million Btu) of fossil fuel and for which construction or modification began on or after the date or proposal of the regulations. This document contains background information, environmental and economic impact assessments, and the rationale for the standards, as proposed under 40 CFR Part 60, Subpart Da.

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Electric Utility Steam Generating Units
Background Information for Proposed NO_x Emission Standards

Emission Standards and Engineering Division

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air, Noise, and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

July 1978

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for Proposed NO_x Emission Standards for
Electric Utility Steam Generating Units

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1. SUMMARY

1.1 PROPOSED STANDARDS

This Background Information document supports proposed nitrogen oxides (NO_x) emission limits for the combustion of pulverized coal (except lignite and coal refuse) in new electric utility steam generating units with heat input rates greater than 73 MW (250 million Btu per hr). The proposed NO_x emission limits for units which burn lignite, coal refuse, shale oil, fuels derived from coal, and other liquid and gaseous fuels are based in other studies, as noted in Chapter 9, and are not discussed in this document. Additional information may be found in the preamble and regulation for Subpart Da in the Federal Register.

The proposed emission limits under 40 CFR Part 60, Subpart Da would restrict NO_x emissions to:

> 86 ng/J heat input (0.20 lb/million Btu) from the combustion of any gaseous fuel, except gaseous fuel derived from coal;
>
> 130 ng/J heat input (0.30 lb/million Btu) from the combustion of any liquid fuel, except shale oil or liquid fuel derived from coal;
>
> 210 ng/J heat input (0.50 lb/million Btu) from the combustion of subbituminous coal, shale oil, or any fuel derived from coal.

> 340 ng/J heat input (0.80 lb/million Btu) from the combustion in a slag tap furnace of any fuel containing more than 25 percent, by weight, lignite which has been mined in North Dakota, South Dakota, or Montana;
>
> 260 ng/J heat input (0.60 lb/million But) from the combustion of any solid fuel not covered above, except that the combustion of any fuel containing more than 25 percent, by weight, coal refuse is exempt from the standards.

These emission limits would be monitored continuously, based on a daily averaging period of 24 hours.

Control of NO_x emissions from pulverized coal-fired electric utility steam generating units is achieved by modifying the way the coal is combusted in the furnace. The best combustion modification system is a combination of staged combustion, low excess air, and reduced heat release rate.

1.2 ENVIRONMENTAL IMPACT

The proposed limits would reduce NO_x emissions by 14 to 29 percent from most pulverized coal-fired units without adversely affecting water quality, solid waste disposal, or energy conservation. Furthermore, the proposed NO_x emission limits would not cause signficant increases in other air pollutants, including sulfur dioxide, particulate matter, carbon monoxide, and hydrocarbons.

1.3 ECONOMIC IMPACT

An economic impact assessment of the proposed regulations has been prepared, as required under section 317 of the Clean Air Act (as amended in 1977). The proposed regulations would have small or negligible impacts on: the costs of compliance; inflation or recession; competition with respect to small business; consumer costs; and energy use. A complete economic impact analysis appears in Chapter 8.

The environmental and economic impacts of the proposed emission limits are summarized in Table 1-1.

Table 1-1. MATRIX OF ENVIRONMENTAL AND ECONOMIC IMPACTS OF THE PROPOSED NO_x EMISSION LIMITS

Administrative Action	Air Impact	Water Impact	Solid Waste Impact	Energy Impact	Noise and Radiation Impact	Economic Impact	Inflationary Impact
No Limits[a]	-3**	0	0	0	0	0	0
Existing Limits[b]	+2**	0	0	0	0	0	0
Proposed Limits[c]	+3**	0	0	0	0	0	0

[a] Prior to December 23, 1971, there were no limits.

[b] These were promulgated on December 23, 1971, under 40 CFR Part 60, Subpart D.

[c] Proposed under 40 CFR Part 60, Subpart Da in 1978.

KEY:
0 No Impact
1 Negligible Impact
2 Small Impact
3 Moderate Impact
4 Large Impact

+ Beneficial Impact
- Adverse Impact

* Short-Term Impact
** Long-Term Impact
*** Irreversible Impact

2. INTRODUCTION

Standards of performance are proposed following a detailed investigation of air pollution control methods available to the affected industry and the impact of their costs on the industry. This document summarizes the information obtained from such a study. Its purpose is to explain in detail the background and basis of the proposed standards and to facilitate analysis of the proposed standards by interested persons, including those who may not be familiar with the many technical aspects of the industry. To obtain additional copies of this document or the Federal Register notice of proposed standards, write to EPA Library (MD-35), Research Triangle Park, North Carolina 27711. Specify Electric Utility Steam Generating Units - Background Information for Proposed NO_x Emission Standards, report number EPA-450/2-78-005a when ordering.

2.1 AUTHORITY FOR THE STANDARDS

Standards of performance for new stationary sources are established under section 111 of the Clean Air Act (42 U.S.C. 7411), as amended, hereafter referred to as the Act. Section 111 directs the Administrator to establish standards of performance for any category of new stationary sources of air pollution which ". . . causes or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare."

The Act requires that standards of performance for stationary sources reflect, ". . . the degree of emission limitation achievable through the application of the best technological system of continuous emission reduction . . . the Administrator determines has been adequately demonstrated." In addition, for stationary sources whose emissions result from fossil fuel combustion, the standard must also include a percentage reduction in emissions. The Act also provides that the cost of achieving the necessary emission reduction, the nonair quality health and environmental impacts and the energy requirements all be taken into account in establishing standards of performance. The standards apply only to stationary sources, the construction or modification of which commences after regulations are proposed by publication in the Federal Register.

The 1977 amendments to the Act altered or added numerous provisions which apply to the process of establishing standards of performance.

1. EPA is required to list the categories of major stationary sources which have not already been listed and regulated under standards of performance. Regulations must be promulgated for these new categories on the following schedule:

25 percent of the listed categories by August 7, 1980

75 percent of the listed categories by August 7, 1981

100 percent of the listed categories by August 7, 1982

A governor of a State may apply to the Administrator to add a category which is not on the list or to revise a standard of performance.

2. EPA is required to review the standards of performance every four years, and if appropriate, revise them.

3. EPA is authorized to promulgate a design, equipment, work practice, or operational standard when an emission standard is not feasible.

4. The term "standards of performance" is redefined and a new term "technological system of continuous emission reduction" is defined. The new definitions clarify that the control system must be continous and may include a low-polluting or non-polluting process or operation.

5. The time between the proposal and promulgation of a standard under section 111 of the Act is extended to six months.

Standards of performance, by themselves, do not guarantee protection of health or welfare because they are not designed to achieve any specific air quality levels. Rather, they are designed to reflect the degree of emission limitation achievable through application of the best adequately demonstrated technological system of continuous emission reduction, taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements.

Congress had several reasons for including these requirements. First, standards with a degree of uniformity are needed to avoid situations where some States may attract industries by relaxing standards relative to other States. Second, stringent standards enhance the potential for long term growth. Third, stringent standards may help achieve long-term cost savings by avoiding the need for more expensive retrofitting when pollution ceilings may be reduced in the future. Fourth, certain types of standards for coal burning sources can adversely affect the coal market by driving up the price of low-sulfur coal or effectively excluding certain coals from the reserve base because their untreated pollution potentials are high. Congress does not intend that new source performance standards contribute to these problems. Fifth, the standard-setting process should create incentives for improved technology.

Promulgation of standards of performance does not prevent State or local agencies from adopting more stringent emission limitations for the same sources. States are free under section 116 of the Act to establish even more stringent emission limits than those established under section 111 or those necessary to attain or maintain the national ambient air quality standards (NAAQS) under section 110. Thus, new sources may in some cases be subject to limitations more stringent than standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

A similar situation may arise when a major emitting facility is to be constructed in a geographic area which falls under the prevention of significant deterioration of air quality provisions of Part C of the Act. These provisions require, among other things, that major emitting facilities to be constructed in such areas are to be subject to best available control technology. The term "best available control technology" (BACT), as defined in the Act, means ". . . an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 or 112 of this Act."

Although standards of performance are normally structured in terms of numerical emission limits where feasible, alternative approaches are sometimes necessary. In some cases physical measurement of emissions from a new source may be impractical or exorbitantly expensive. Section 111(h) provides that the Administrator may promulgate a design or equipment standard in those cases where it is not feasible to prescribe or enforce a standard of performance. For example, emissions of hydrocarbons from storage vessels for petroleum liquids are greatest during tank filling. The nature of the emissions, high concentrations for short periods during filling, and low concentrations for longer periods during storage, and the configuration of storage tanks make direct emission measurement impractical. Therefore, a more practical approach to standards of performance for storage vessels has been equipment specification.

In addition, section 111(h) authorizes the Administrator to grant waivers of compliance to permit a source to use innovative continuous emission control technology. In order to grant the waiver, the Administrator must find: (1) a substantial likelihood that the technology will produce greater emission reductions than the standards require, or an equivalent reduction at lower economic, energy or environmental cost;

(2) the proposed system has not been adequately demonstrated; (3) the technology will not cause or contribute to an unreasonable risk to public health, welfare or safety; (4) the governor of the State where the source is located consents; and that, (5) the waiver will not prevent the attainment or maintenance of any ambient standard. A waiver may have conditions attached to assure the source will not prevent attainment of any NAAQS. Any such condition will have the force of a performance standard. Finally, waivers have definite end dates and may be terminated earlier if the conditions are not met or if the system fails to perform as expected. In such a case, the source may be given up to three years to meet the standards, with a mandatory progress schedule.

2.2 SELECTION OF CATEGORIES OF STATIONARY SOURCES

Section 111 of the Act directs the Administrator to list categories of stationary sources which have not been listed before. The Administrator, ". . . shall include a category of sources in such list if in his judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." Proposal and promulgation of standards of performance are to follow while adhering to the schedule referred to earlier.

Since passage of the Clean Air Amendments of 1970, considerable attention has been given to the development of a system for assigning priorities to various source categories. The approach specifies areas of interest by considering the broad strategy of the Agency for implementing the Clean Air Act. Often, these "areas" are actually pollutants which are emitted by stationary sources. Source categories which emit these pollutants were then evaluated and ranked by a process involving such factors as (1) the level of emission control (if any) already required by State regulations; (2) estimated levels of control that might be required from standards of performance for the source category; (3) projections of growth and replacement of existing facilities for the source category; and (4) the estimated incremental amount of air pollution that could be prevented, in a preselected future year, by standards of performance for the source category. Sources for which new source performance standards were promulgated or are under development during 1977 or earlier, were selected on these criteria.

The Act amendments of August, 1977, establish specific criteria to be used in determining priorities for all source categories not yet listed by EPA. These are

1) the quantity of air pollutant emissions which each such category will emit, or will be designed to emit;

2) the extent to which each such pollutant may reasonably be anticipated to endanger public health or welfare; and

3) the mobility and competitive nature of each such category of sources and the consequent need for nationally applicable new source standards of performance.

In some cases, it may not be feasible to immediately develop a standard for a source category with a high priority. This might happen when a program of research is needed to develop control techniques or because techniques for sampling and measuring emissions may require refinement. In the developing of standards, differences in the time required to complete the necessary investigation for different source categories must also be considered. For example, substantially more time may be necessary if numerous pollutants must be investigated from a single source category. Further, even late in the development process the schedule for completion of a standard may change. For example, inability to obtain emission data from well-controlled sources in time to pursue the development process in a systematic fashion may force a change in scheduling. Nevertheless, priority ranking is, and will continue to be, used to establish the order in which projects are initiated and resources assigned.

After the source category has been chosen, determining the types of facilities within the source category to which the standard will apply must be decided. A source category may have several facilities that cause air pollution and emissions from some of these facilities may be insignificant or very expensive to control. Economic studies of the source category and of applicable control technology may show that air pollution control is better served by applying standards to the more severe pollution sources. For this reason, and because there be no adequately demonstrated system for controlling emissions from certain facilities, standards often do not apply to all facilities at a source. For the same reasons, the standards may not apply to all air pollutants emitted. Thus, although a source category may be selected to be covered by a standard of performance, not all pollutants or facilities within that source category may be covered by the standards.

2.3 PROCEDURE FOR DEVELOPMENT OF STANDARDS OF PERFORMANCE

Standards of performance must (1) realistically reflect best demonstrated control practice; (2) adequately consider the cost, and the nonair quality health and environmental impacts and energy requirements of such control; (3) be applicable to existing sources that are modified or reconstructed as well as new installations; and (4) meet these conditions for all variations of operating conditions being considered anywhere in the country.

The objective of a program for development of standards is to identify the best technological system of continuous emission reduction which has been adequately demonstrated. The legislative history of section 111 and various court decisions make clear that the Administrator's judgment of what is adequately demonstrated is not limited to systems that are in actual routine use. The search may include a technical assessment of control systems which have been adequately demonstrated but for which there is limited operational experience. In most cases, determination of the ". . . degree of emission reduction achievable . . ." is based on results of tests of emissions from well controlled existing sources. At times, this has required the investigation and measurement of emissions from control systems found in other industrialized countries that have developed more effective systems of control than those available in the United States.

Since the best demonstrated systems of emission reduction may not be in widespread use, the data base upon which standards are developed may be somewhat limited. Test data on existing well-controlled sources are obvious starting points in developing emission limits for new sources. However, since the control of existing sources generally represents retrofit technology or was originally designed to meet an existing State or local regulation, new sources may be able to meet more stringent emission standards. Accordingly, other information must be considered before a judgment can be made as to the level at which the emission standard should be set.

A process for the development of a standard has evolved which takes into account the following considerations.

1. Emissions from existing well-controlled sources as measured.

2. Data on emissions from such sources are assessed with consideration of such factors as: (a) how representative the tested source is in regard to feedstock, operation, size, age, etc.; (b) age and maintenance of the control equipment tested; (c) design uncertainties of control equipment being considered; and (d) the degree of uncertainty that new sources will be able to achieve similar levels of control.

3. Information from pilot and prototype installations, guarantees by vendors of control equipment, unconstructed but contracted projects, foreign technology, and published literature are also considered during the standard development process. This is especially important for sources where "emerging" technology appears to be a significant alternative.

4. Where possible, standards are developed which permit the use of more than one control technique or licensed process.

5. Where possible, standards are developed to encourage or permit the use of process modifications or new processes as a method of control rather than "add-on" systems of air pollution control.

6. In appropriate cases, standards are developed to permit the use of systems capable of controlling more than one pollutant. As an example, a scrubber can remove both gaseous and particulate emissions, but an electrostatic precipitator is specific to particulate matter.

7. Where appropriate, standards for visible emissions are developed in conjunction with concentration/mass emission standards. The opacity standard is established at a level that will require proper operation and maintenance of the emission control system installed to meet the

concentration/mass standard on a day-to-day basis. In some cases, however, it is not possible to develop concentration/mass standards, such as with fugitive sources of emissions. In these cases, only opacity standards may be developed to limit emissions.

2.4 CONSIDERATION OF COSTS

Section 317 of the Act requires, among other things, an economic impact assessment with respect to any standard of performance established under section 111 of the Act. The assessment is required to contain an analysis of:

(1) the costs of compliance with the regulation and standard including the extent to which the cost of compliance varies depending on the effective date of the standard or regulation and the development of less expensive or more efficient methods of compliance;

(2) the potential inflationary recessionary effects of the standard or regulation;

(3) the effects on competition of the standard or regulation with respect to small business;

(4) the effects of the standard or regulation on consumer cost, and,

(5) the effects of the standard or regulation on energy use.

Section 317 requires that the economic impact assessment be as extensive as practible, taking into account the time and resources available to EPA.

The economic impact of a proposed standard upon an industry is usually addressed both in absolute terms and by comparison with the control costs that would be incurred as a result of compliance with typical existing State control regulations. An incremental approach is taken since both new and existing plants would be required to comply with State regulations in the absence of a Federal standard of performance. This approach requires a detailed analysis of the impact upon the industry resulting from the cost differential that exists between a standard of performance and the typical State standard.

The costs for control of air pollutants are not the only costs considered. Total environmental costs for control of water pollutants as well as air pollutants are analyzed wherever possible.

A thorough study of the profitability and price-setting mechanisms of the industry is essential to the analysis so that an accurate estimate of potential adverse economic impacts can be made. It is also essential to know the capital requirements placed on plants in the absence of Federal standards of performance so that the additional capital requirements necessitated by these standards can be placed in the proper perspective. Finally, it is necessary to recognize any constraints on capital availability within an industry, as this factor also influences the ability of new plants to generate the capital required for installation of additional control equipment needed to meet the standards of performance

2.5 CONSIDERATION OF ENVIRONMENTAL IMPACTS

Section 102(2)(C) of the National Environmental Policy Act (NEPA) of 1969 requires Federal agencies to prepare detailed environmental impact statements on proposals for legislation and other major Federal actions significantly affecting the quality of the human environment. The objective of NEPA is to build into the decision-making process of Federal agencies a careful consideration of all environmental aspects of proposed actions.

In a number of legal challenges to standards of performance for various industries, the Federal Courts of Appeals have held that environmental impact statements need not be prepared by the Agency for proposed actions under section 111 of the Clean Air Act. Essentially, the Federal Courts of Appeals have determined that " . . . the best system of emission reduction, . . . require(s) the Administrator to take into account counter-productive environmental effects of a proposed standard, as well as economic costs to the industry . . ." On this basis, therefore, the Courts ". . . established a narrow exemption from NEPA for EPA determination under section 111."

In addition to these judicial determinations, the Energy Supply and Environmental Coordination Act (ESECA) of 1974 (PL-93-319) specifically exempted proposed actions under the Clean Air Act from NEPA requirements. According to section 7(c)(1), "No action taken under the Clean Air Act shall be deemed a major Federal action significantly affecting the quality of the human environment within the meaning of the National Environmental Policy Act of 1969."

The Agency has concluded, however, that the preparation of environmental impact statements could have beneficial effects on certain regulatory actions. Consequently, while not legally required to do so by section 102(2)(C) of NEPA, environmental impact statements will be prepared for various regulatory actions, including standards of performance developed under section 111 of the Act. This voluntary preparation of environmental impact statements, however, in no way legally subjects the Agency to NEPA requirements.

To implement this policy, a separate section is included in this document which is devoted solely to an analysis of the potential environmental impacts associated with the proposed standards. Both adverse and beneficial impacts in such areas as air and water pollution, increased solid waste disposal, and increased energy consumption are identified and discussed.

2.6 IMPACT ON EXISTING SOURCES

Section 111 of the Act defines a new source as ". . . any stationary source, the construction or modification of which is commenced . . . " after the proposed standards are published. An existing source becomes a new source if the source is modified or is reconstructed. Both modification and reconstruction are defined in amendments to the general provisions of Subpart A of 40 CFR Part 60 which were promulgated in the Federal Register on December 16, 1975 (40 FR 58416). Any physical or operational change to an existing facility which results in an increase in the emission rate of any pollutant for which a standard applies is considered a modification. Reconstruction, on the other hand, means the replacement of components of an existing facility to the extent that the fixed capital cost exceeds 50 percent of the cost of constructing a comparable entirely new source and that it be technically and economically feasible to meet the applicable standards. In such cases, reconstruction is equivalent to new construction.

Promulgation of a standard of performance requires States to establish standards of performance for existing sources in the same industry under section 111(d) of the Act if the standard for new sources limits emissions of a designated pollutant (i.e. a pollutant for which air quality criteria have not been issued under section 108 or which has not been listed as a hazardous pollutant under section 112). If a State does not act, EPA must establish such standards. General provisions outlining procedures for control of existing sources under section 111(d) were promulgated on November 17, 1975, as Subpart B of 40 CFR Part 60 (40 FR 53340).

2.7 REVISION OF STANDARDS OF PERFORMANCE

Congress was aware that the level of air pollution control achievable by any industry may improve with technological advances. Accordingly, section 111 of the Act provides that the Administrator ". . . shall, at least every four years, review and, if appropriate, revise . . ." the standards. Revisions are made to assure that the standards continue to reflect the best systems that become available in the future. Such revisions will not be retroactive but will apply to stationary sources constructed or modified after the proposal of the revised standards.

3. THE FOSSIL FUEL STEAM ELECTRIC UTILITY INDUSTRY

3.1 GENERAL

3.1.1 Description and Uses of Large Steam Generators

A large fossil fuel-fired steam generator is a unit of more than 73 megawatts (250 X 10^6 BTU/Hr) heat input. A 73 megawatt (250 X 10^6 BTU/Hr) steam generator produces enough steam to generate approximately 25 megawatts of electric power.[1,2] The largest fossil fuel-fired steam generators in the United States produce enough steam to generate 1300 megawatts.[3] As shown by Table 3-1, nearly all large fossil fuel-fired steam generators are sold to the electric utility industry for generation of electric power.[4] A few large steam generators are sold to produce steam for industrial use.

3.1.2 Electric Utility Industry Statistics

At the end of 1975, the total capacity of fossil fuel-fired steam generator power units was 347.7 gigawatts.[3] Table 3-2 shows statistics on 1975 fuel consumption.[3] As shown, 60 percent of the thermal energy was supplied by coal and the remainder was about equally split between gas and oil.

TABLE 3-1

COMPARISON OF ANNUAL SALES OF WATERTUBE GENERATORS[4] TO UTILITIES AND TO ALL USERS CAPACITIES >31.5 KILOGRAMS OF STEAM PER SECOND (250,000 lb/hr)

Year	Total Steam Capacity Sold Megagrams per Second (10^6 lb/hr)	
	To All Users	To Utilities
1961	13.02 (103.3)	12.40 (98.4)
1962	10.05 (79.8)	9.69 (76.9)
1963	14.92 (118.4)	13.94 (110.6)
1964	18.85 (149.6)	16.93 (134.4)
1965	24.03 (190.7)	21.37 (169.6)
1966	22.43 (178.0)	20.69 (164.2)
1967	26.11 (207.2)	24.99 (198.3)
1968	25.14 (199.5)	23.89 (189.6)
1969	27.00 (214.3)	24.99 (198.3)
1970	31.08 (246.7)	29.74 (236.0)
1971	18.60 (147.6)	17.83 (141.5)
1972	21.31 (169.1)	19.35 (153.6)
1973	33.30 (264.3)	30.47 (241.8)
1974	37.16 (294.9)	34.41 (273.1)
1975	13.37 (106.1)	11.37 (90.2)
1976	7.17 (56.9)	6.27 (49.8)
TOTAL	343.54 (2726.4)	318.33 (2526.3)

TABLE 3-2

FOSSIL FUEL CONSUMPTION FOR POWER GENERATION 1975[3]

Fossil Fuel	Consumption	Percent of Total Heat Input
Coal	366.1×10^9 Kilograms (403.6×10^6 tons)	60.0
Oil	72.50×10^6 Cubic Metres (456.0×10^6 Bbl)	19.2
Gas	8.38×10^{10} Cubic Metres (2.96×10^{12} Ft^3)	20.8

TABLE 3-3

1974 UNITED STATES ELECTRIC UTILITY POWER GENERATION[5]

Type	Power Generation Exajoules (10^9 Kw Hr)	Percent
Fuel Burning[(a)]	5.28 (1466)	78.5
Nuclear	.40 (110)	5.9
Hydropower	1.05 (291)	15.6
TOTAL	6.73 (1867)	100.0

(a) Includes oil and gas turbines

Table 3-3 shows 1974 United States total electric utility energy generation.[5] Additional electrical energy is generated by industry, remote domestic units, and by automobiles, aircraft, construction equipment, locomotives, and vessels. As shown in Table 3-3, about 79 percent of the 1974 electric utility energy was generated from fossil fuels. About 16 percent was generated by hydropower systems and about 6 percent was generated by nuclear power plants.

Table 3-4 shows use of 1974 electric utility generated energy by consuming sector.[5] As shown, about 58 percent of the total electrical energy was used for domestic or commercial purposes. About 42 percent was used by the industrial sector. Transportation uses very little of the electrical energy generated by power plants because it is more practical to equip mobile units with internal generating systems.

TABLE 3-4

UNITED STATES USE OF ELECTRICAL ENERGY BY CONSUMING SECTOR 1974[5]

Sector	Exajoules Used (10^{15} Btu)	Percent
Household and Commercial	3.89 (3.69)	57.9
Industrial	2.81 (2.67)	41.8
Transportation[(a)]	0.02 (.016)	0.3
TOTAL	6.72 (6.37)	100.0

(a) Does not include electrical energy generated by transportation equipment, such as automobile generators, etc.

Table 3-5 shows total United States energy consumption by consuming sector and energy source.[5] As shown, United States energy is derived primarily from fossil fuels with small percentages derived from nuclear, hydropower, and geothermal energy sources. About 46 percent is furnished by petroleum, 30 percent by natural gas, and 18 percent by coal. About 27 percent of United States energy is used for electric power generation. About the same proportion is used by the industrial and transportation sectors. Household and commercial sectors use about 19 percent of the total energy. Most of the coal is used for electric power generation with other large use by the industrial sector. The transporation sector uses more than one-half of petroleum derived energy. Household and commercial, industrial, and electrical generation sectors use other large quanitites of petroleum derived energy. As shown by Table 3-5, about one-half of the energy used by industry other than electrical energy comes from natural gas. Household and commercial and electrical generation sectors also use large volumes of natural gas. Little natural gas is used by the transportation sector.

3.1.3 New Source Growth Projections

For new source growth projections, see "Review of New Source Standards for SO_2 Emissions from Coal-Fired Utility Boilers, Volume 1, Non Air-Quality Impact Assessment," Teknekron, Inc., Emission Standards and Engineering Division, Office of Air Quality Planning and Standards, U. S. Environmental Protection Agency, Research Triangle Park, North Carolina, 1978.

TABLE 3-5 UNITED STATES PRIMARY ENERGY CONSUMPTION BY CONSUMING SECTOR AND ENERGY SOURCE[5] 1974
Exajoules (10^{15} Btu)

Consuming Sector[(a)]	Coal	Petroleum	Natural Gas	Nuclear	Hydropower and Geothermal	Total	Percent
Household and Commercial	0.31 (0.29)	6.75 (6.39)	7.51 (7.116)	--	--	14.57 (13.797)	18.9
Industrial	4.44 (4.208)	6.38 (6.044)	11.75 (11.129)	--	--	22.57 (21.415)	29.3
Transportation	0.01 (0.01)	18.59 (17.608)	0.70 (0.664)	--	--	19.29 (18.274)	25.0
Electrical Generation	9.15 (8.668)	3.64 (3.448)	3.51 (3.328)	1.24 (1.173)	3.19 (3.018)	20.73 (19.635)	26.9
Total	13.90 (13.169)	35.36 (33.490)	23.47 (22.237)	1.24 (1.173)	3.19 (3.018)	77.16 (73.121)	100.0
Percent	18.0	45.9	30.4	1.6	4.1	100.0	

(a) Excludes use of electrical energy by household, commercial, industrial and transportation sectors

3.2 FACILITIES, FUELS, AND EMISSIONS

3.2.1 Facilities and Fuels

Large fossil fuel-fired steam generators are classified in several different ways as follows:

Fuel

Firing Method

Physical state of ash

Fluid flow

Draft

Manufacture

3.2.1.1 Common Characteristics

Figure 3-1 shows a typical large fossil fuel-fired steam generator system. Although there is a wide difference among steam generators, they have common characteristics. A common design objective is to produce the required quantity and quality of steam at minimum cost. Air preheated to as much as 315°C (600°F) by the combustion gases is introduced into the combustion chamber with the fuel through multiple burners strategically arranged to promote optimum combustion conditions. In the combustion chamber, the combustible matter reacts with the oxygen of the air to release thermal energy at temperatures exceeding 1100°C (2000°F).[6] The walls of the combustion chamber are lined with water-filled tubes which absorb thermal energy and generate steam. The water tubes are filled with liquid or vapor, depending on pressure and temperature conditions.

Heat transfer in the combustion chamber cools the combustion gases to about 1100°C (2000°F).[6] The cooler combustion gases flow from the

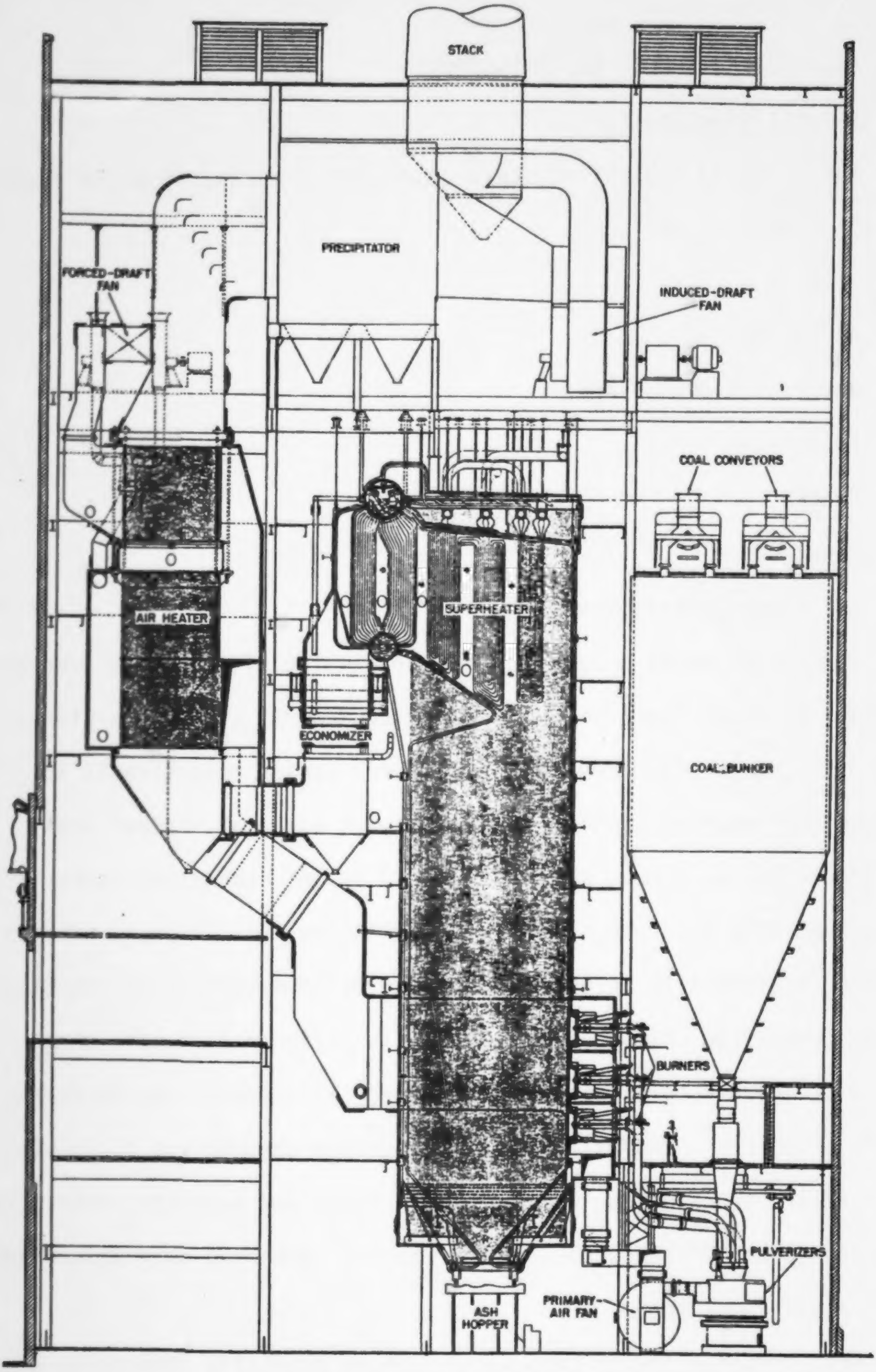
STACK
PRECIPITATOR
FORCED-DRAFT FAN
INDUCED-DRAFT FAN
COAL CONVEYORS
AIR HEATER
SUPERHEATER
ECONOMIZER
COAL BUNKER
BURNERS
PULVERIZERS
PRIMARY-AIR FAN
ASH HOPPER

Figure 3-1

Typical pulverized coal fired boiler

combustion chamber to the superheat and reheat sections of the steam generator where further heat transfer and gas cooling occur. Steam superheat and reheat are necessary for thermodynamic efficiency and also to prevent steam condensation which would damage the blades of the steam turbines which turn the electric power generators. Modern steam electric power generation systems use steam at pressures ranging from 13.8 to 27.6 megapascals (2000-4000 PSI) at a minimum temperature of about 540°C (1000°F).[6] Steam turbines are designed in stages so that steam is sent back to the steam generator for reheat between stages. Most modern systems are designed with a superheat stage followed by a reheat stage. Some systems are designed with more than one reheat stage. The most efficient fossil fuel-fired steam-electric system generates 3.6 megajoules (one kilowatt hour) of electrical energy from 9.2 megajoules (8714 Btu) of gross thermal energy input.[7] Most modern systems generate 3.6 megajoules (one kilowatt hour) of electric energy from less than 10.60 megajoules (10,000 Btu) heat input.[7] Because of the thermal energy losses of the steam turbine thermodynamic cycle and the heat losses from the steam generator, less than 40 percent of the thermal energy of the fuel is converted to electrical energy. About 12 to 20 percent of the gross heat input is lost in the steam generation system and the remainder is lost in the steam turbine system, mostly as latent heat in the turbine condenser.[6]

Combustion gases from the superheat and reheat sections flow to the economizer section where heat is transferred to the steam generator feedwater. Combustion gas temperature out of the economizer ranges from 315°C to 480°C (600-900°F).[6] Combustion gases from the economizer flow to the air preheater. When hot-side electrostatic precipitators are used for fly ash collection, the dust collection system is located between the economizer and air preheater. With cold-side electrostatic precipitators, the dust collection system and flue gas desulfurization system, if any, are located after the air preheater and before the induced draft fan and stack. The air preheater heats the air flowing to the steam generator combustion chamber. Combustion gas temperature out of the air preheater ranges from 120°C to 200°C (250-400°F).[6]

To minimize heat loss, large steam generator air preheaters are designed to reduce stack temperature to the lowest level which does not cause corrosion problems. Corrosion will occur in and after the air preheater if the combustion gas temperature falls below the dew point of sulfuric acid mist. Consequently, air preheaters are designed for higher outlet temperatures when high sulfur fuels are fired than when low sulfur fuels are burned. Heat losses from the steam generation system are also minimized by insulating hot surfaces and by minimizing the quantity of combustion air. The extent of combustion air reduction is limited by the needs for nearly complete oxidation of the fuel, steam superheat, minimal slagging and tube wastage (corrosion), and flame stability.[8,9,10,11] These factors are related to NO_x control and are discussed in greater depth in Chapters 4 and 6.

3.2.1.2 Fuels

Large fossil fuel-fired steam generators are designed to fire either coal, oil, or gas or a combination of these fuels. Since no new large oil or gas-fired steam generators are planned for the future, no data are reported for oil or gas fuels. Discussion of coal is largely limited to coal other than lignite because regulations for limiting NO_x emissions from large lignite-fired steam generators are being developed separately.[12]

To distinguish between lignite, subbituminous, and other coals, ASTM Specification D388 defines lignite as a coal with a moist, mineral matter free, calorific value less than 19.3 megajoules per kilogram (8300 Btu/lb)[6] and subbituminous coal as a coal with a moist, mineral matter free calorific value ranging from 19.3 to 26.8 megajoules per kilogram (8300-11,500 Btu/lb). The moist, mineral matter free calorific value of coal is calculated as follows:[6,13]

Moist, Mineral-Matter Free Calorific Value (megajoules per kilogram)=

$$\frac{HVM - .1163S}{100 - (1.08A + .55S)} \times 100$$

expressed in the English units of ASTM D388 is:

Moist, Mineral-Matter Free Calorific Value (Btu per pound) =

$$\frac{HVE - 50S}{100 - (1.08A + .55S)} \times 100$$

where:

HVM = metric unit heating value of moist coal in megajoules per kilogram

HVE = English unit heating value of moist coal in Btu per pound

S = percent sulfur by weight

A = percent ash by weight

The prime fuel characteristics affecting NO_x control are moisture, nitrogen, heating value, sulfur, ash composition, and ash consistency.[8,9,10,11] Moisture, nitrogen, and heating value affect NO_x formation. Sulfur, ash composition, and ash consistency may limit the way a steam generator can be designed to limit NO_x emissions.[8,9,10,11] The effect of the foregoing characteristics on NO_x control is disucssed in Chapters 4 and 6.

Table 3-6 shows selected properties of a variety of United States coals.[6] As shown, the Western coals usually have low sulfur content, high moisture content, and low heating value. Eastern coals contain less moisture and have a higher heating value. The sulfur content of Eastern coal ranges from less than 1 percent to more than 4 percent.

Table 3-7 shows the ranges in nitrogen content for various ranks of United States coal.[12,14] Table 3-8 shows the range of coal ash composition for various ranks of United States coals.[15] As shown, the percentages of the various ash constituents varies widely. Table 3-9 shows ash softening temperatures for several United States coals.[6] As shown, the difference between the ash softening temperature in a reducing and oxidizing atmosphere is greater when Fe_2O_3 is a large fraction of the ash. Chapters 4 and 6 discuss how coal nitrogen content, ash composition, and ash consistency affect NO_x control.

TABLE 3-7

NITROGEN CONTENT OF UNITED STATES COALS

	Nitrogen Content Percent by Weight, Moisture, Ash-free Basis
Lignite[12]	1.0 - 1.4
Subbituminous[14]	1.2 - 1.7
High Volatile C Bituminous[14]	1.6 - 2.1
High Volatile B Bituminous[14]	1.7
High Volatile A Bituminous[14]	1.6 - 1.9

Table 3-6

CHARACTERISTICS OF SEVENTEEN SELECTED UNITED STATES COALS [6]

Coal Description	Proximate Analysis - Percent By Weight, Moisture Basis				Element Analysis - Percent By Weight, Dry, Ash-Free Basis					Heating Value Moist, Mineral Matter Free Megajoules/Kilogram (Btu/lb)
	Moisture	Volatile Matter	Fixed Carbon	Ash	S	C	H_2	O_2	N_2	
Pennsylvania Meta-Anthracite	4.5	1.7	84.1	9.7	0.77	93.9	2.1	2.3	0.3	33.22 (14,280)
Pennsylvania Anthracite	2.5	6.2	79.4	11.9	0.60	93.5	2.6	2.3	0.9	34.61 (14,480)
Virginia Semi Anthracite	2.0	10.6	67.2	20.2	0.62	90.7	4.2	3.3	1.0	35.68 (15,340)
W. Virginia Low Volatile Bituminous	1.0	16.6	77.3	5.1	0.74	90.4	4.8	2.7	1.3	36.29 (15,600)
Pennsylvania Low Volatile Bituminous	1.3	17.5	70.9	10.3	1.68	89.4	4.8	2.4	1.5	36.27 (15,595)
Pennsylvania Medium Volatile Bituminous	1.5	20.8	67.5	10.2	1.68	88.6	4.8	3.1	1.6	36.02 (15,485)
Pennsylvania Medium Volatile Bituminous	1.5	23.4	64.9	10.2	2.20	87.6	5.2	3.3	1.4	36.24 (15,580)
Pennsylvania High Volatile Bituminous	1.5	30.7	56.6	11.2	1.82	85.0	5.4	5.8	1.7	35.42 (15,230)
Kentucky High Volatile A Bituminous	2.5	36.7	57.5	3.3	0.70	85.5	5.5	6.7	1.6	34.98 (15,040)
Ohio High Volatile A Bituminous	3.6	40.0	47.3	9.1	4.00	80.9	5.7	7.4	1.4	33.45 (14,380)
Illinois High Volatile B Bituminous	5.8	36.2	46.3	11.7	2.70	80.5	5.5	9.1	1.6	31.89 (13,710)
Utah High Volatile B Bituminous	5.2	38.2	50.2	6.4	0.90	79.8	5.6	11.8	1.7	31.54 (13,560)
Illinois High Volatile C Bituminous	12.2	38.8	40.0	9.0	3.20	79.2	5.7	9.5	1.5	28.75 (12,360)
Montana Subbituminous A	14.1	32.2	46.7	7.0	0.43	80.9	5.1	12.2	1.3	28.09 (12,075)
Wyoming Subbituminous B	25.0	30.5	40.8	3.7	0.30	75.9	5.1	17.0	1.6	22.67 (9,745)
Wyoming Subbituminous C	31.0	31.4	32.8	4.8	0.55	74.0	5.6	18.6	0.9	20.45 (8,790)
North Dakota Lignite A	37.0	26.6	32.2	4.2	0.40	72.7	4.9	20.8	0.9	17.70 (7,610)

TABLE 3-8

VARIATIONS IN COAL ASH COMPOSITION WITH RANK[15]

Rank	% SiO_2	%Al_2O_3	%Fe_2O_3	% TiO_2	%CaO	%MgO	%Na_2O	%K_2O	% SO_3
Anthracite	48-68	25-44	2-10	1.0 - 2	0.2 - 4	0.2 - 1	--	--	0.1 - 1
Bituminous	7-68	4-39	2-44	0.5 - 4	0.7 -36	0.1 - 4	0.2 - 3	0.2 -4	0.1 - 32
Subbituminous	17-58	4-35	3-19	0.6 - 2	2.2 -52	0.5 - 8	--	--	3.0 - 16
Lignite	6-40	4-26	1-34	0.0 -0.8	12.4 -52	2.8-14	0.2 -28	0.1 -1.3	8.3 - 32

TABLE 3-9

ASH SOFTENING TEMPERATURE AND ASH COMPOSITION OF SELECTED UNITED STATES COALS[6]

	Ash Softening Temperature Degrees Celsius (°F)		Ash Composition Percent By Weight, Dry							
	Reducing Atmosphere	Oxidizing Atmosphere	SiO_2	Al_2O_3	TiO_2	Fe_2O_3	CaO	MgO	Na_2O	K_2O
Pocahontas No. 3, West Virginia, Low Volatile Bituminous	(2900+)	(2900+)	60.0	30.0	1.6	4.0	0.6	0.6	0.5	1.5
Ohio No. 9, High Volatile Bituminous	(2450)	(2605)	47.27	22.96	1.00	22.81	1.30	0.85	0.28	1.97
Pittsburgh and West Virginia, High Volatile Bituminous	(2175)	(2385)	37.64	20.11	0.81	29.28	4.25	1.25	0.80	1.60
Illinois No. 6, High Volatile Bituminous	(2160)	(2430)	47.52	17.87	0.78	20.13	5.75	1.02	0.36	1.77
Utah, High Volatile Bituminous	(2140)	(2220)	48.0	11.5	0.6	7.0	25.0	4.0	1.2	0.2
Wyoming, Subbituminous	(2180)	(2220)	24.0	20.0	0.7	11.0	26.0	4.0	0.2	0.5
Texas Lignite	(2130)	(2190)	41.8	13.6	1.5	6.6	17.6	2.5	0.6	0.1

3.2.1.3 Firing Methods for Large Pulverized Coal-Fired Generators

The three basic types of pulverized coal-fired steam generators are single wall, horizontally-opposed, and tangential-fired designs. As discussed later, single wall, horizontally-opposed, or tangential-fired units can be designed for either dry ash or slag tap (molten ash) operation. Figure 3-2 depicts a single wall-fired design. As shown, the burners are located in horizontal rows in one wall of the furnace. Figure 3-3 shows a horizontally-opposed, slag tap design. The burners are located in horizontal rows in opposite furnace walls. Figure 3-4 shows a tangential, dry ash design. The burners are located vertically at each of the four corners of the furnace and are directed to create a swirling ball of hot combustion gases.

Slag tap designs cannot be used for all types of coal. The ash fusibility temperature characteristics of a coal determine if a slag tap design can be used. Although no maximum ash fusibility temperature can be quoted, slag tap units cannot be designed to fire coal which produces ash of high fusibility temperature. Dry ash units can be designed to fire coal of either high or low ash fusibility temperature. When coal ash fusibility temperature is low, larger combustion chambers are provided for dry tap designs. Enlarging the combustion chamber and locating the burners away from the bottom reduces bottom temperatures and produces a dry ash. Dry ash units specially designed to fire coal of low ash fusibility temperature are the most adaptable for firing a variety of coals. However, expert advice is needed to determine if any given steam generator is adaptable to different kinds of coal.

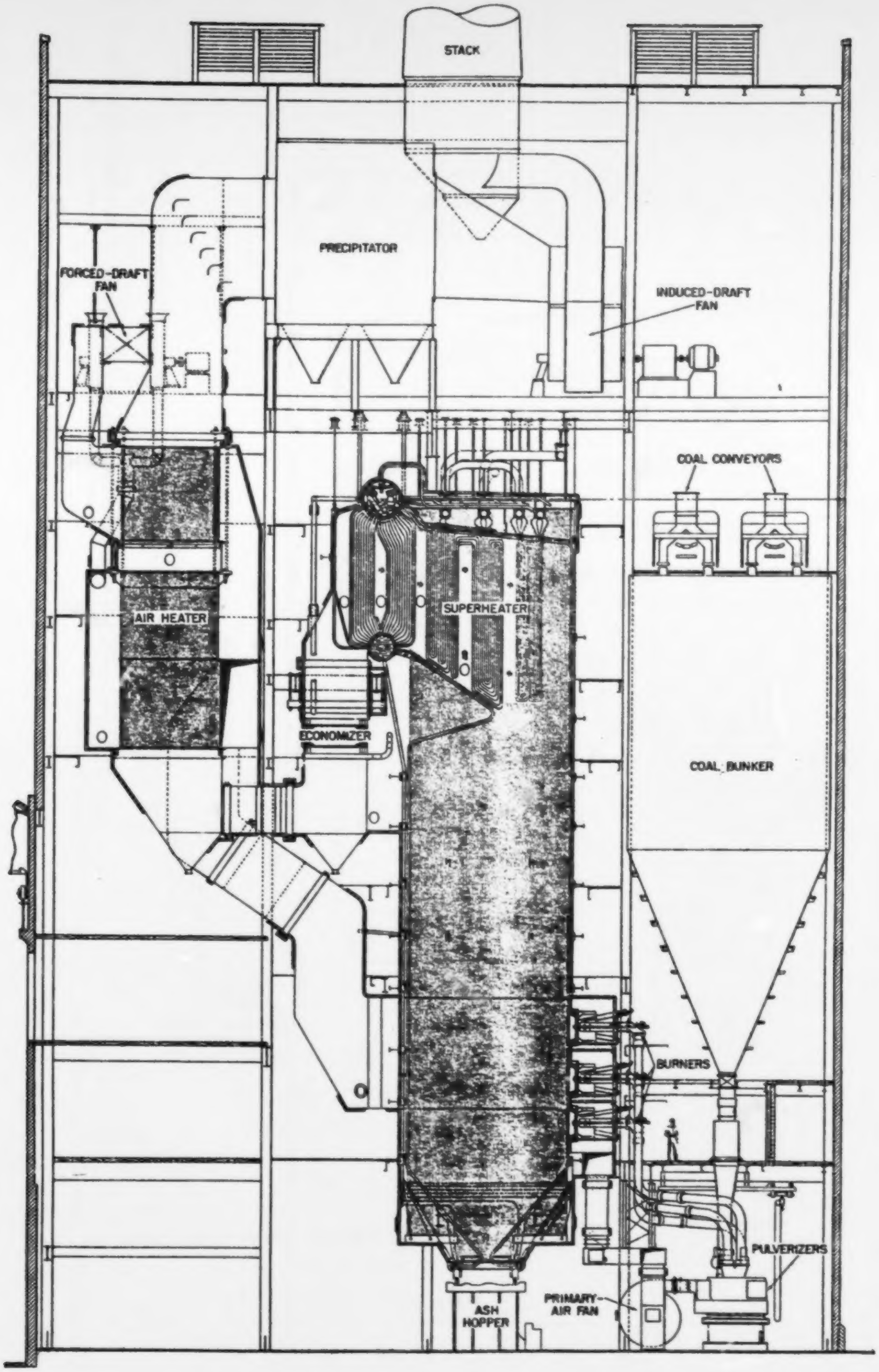
STACK
PRECIPITATOR
FORCED-DRAFT FAN
INDUCED-DRAFT FAN
COAL CONVEYORS
AIR HEATER
SUPERHEATER
ECONOMIZER
COAL BUNKER
BURNERS
PULVERIZERS
PRIMARY-AIR FAN
ASH HOPPER

Figure 3-2

FRONT WALL-FIRED BOILER

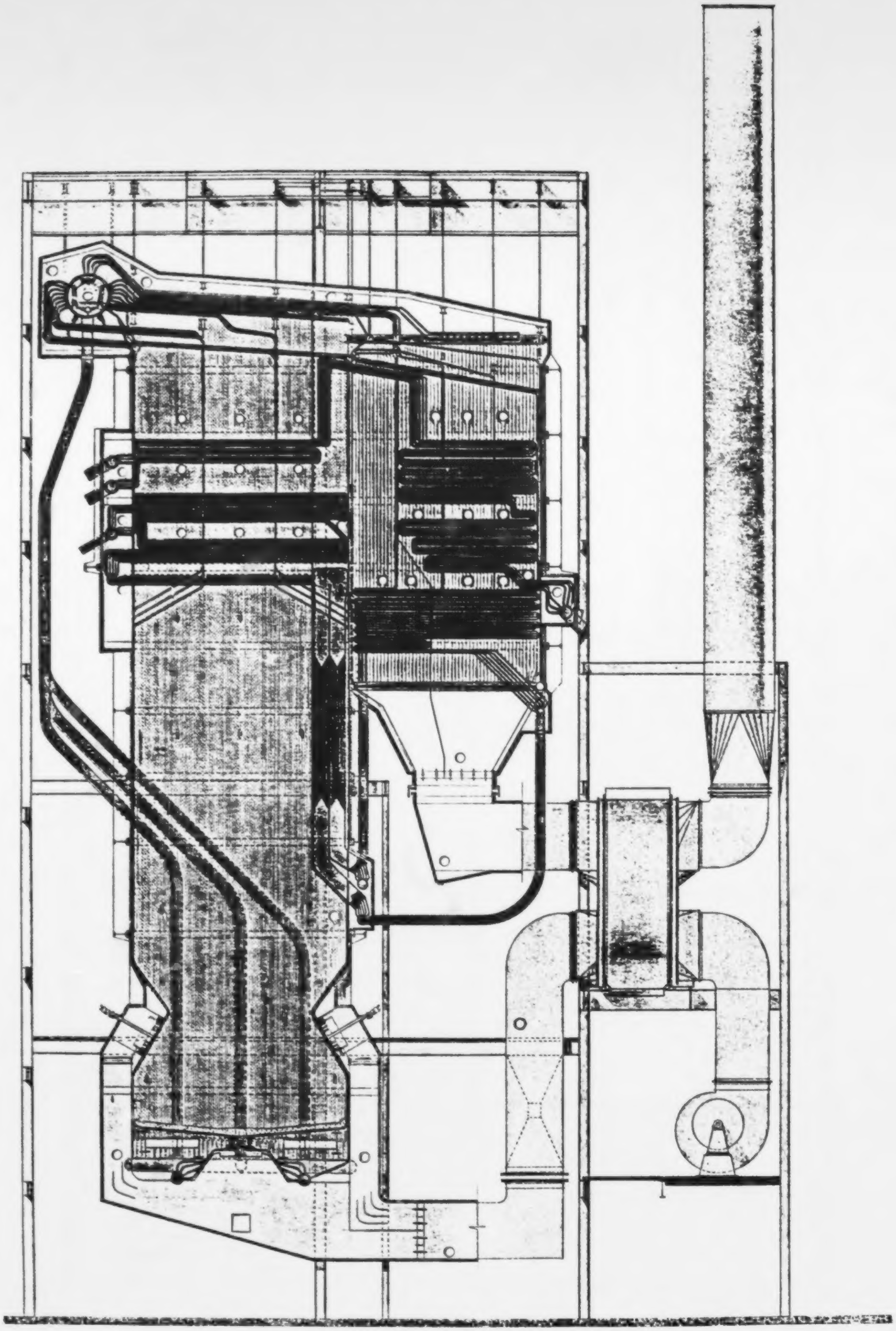

Figure 3-3

HORIZONTALLY OPPOSED SLAG TAP BOILER

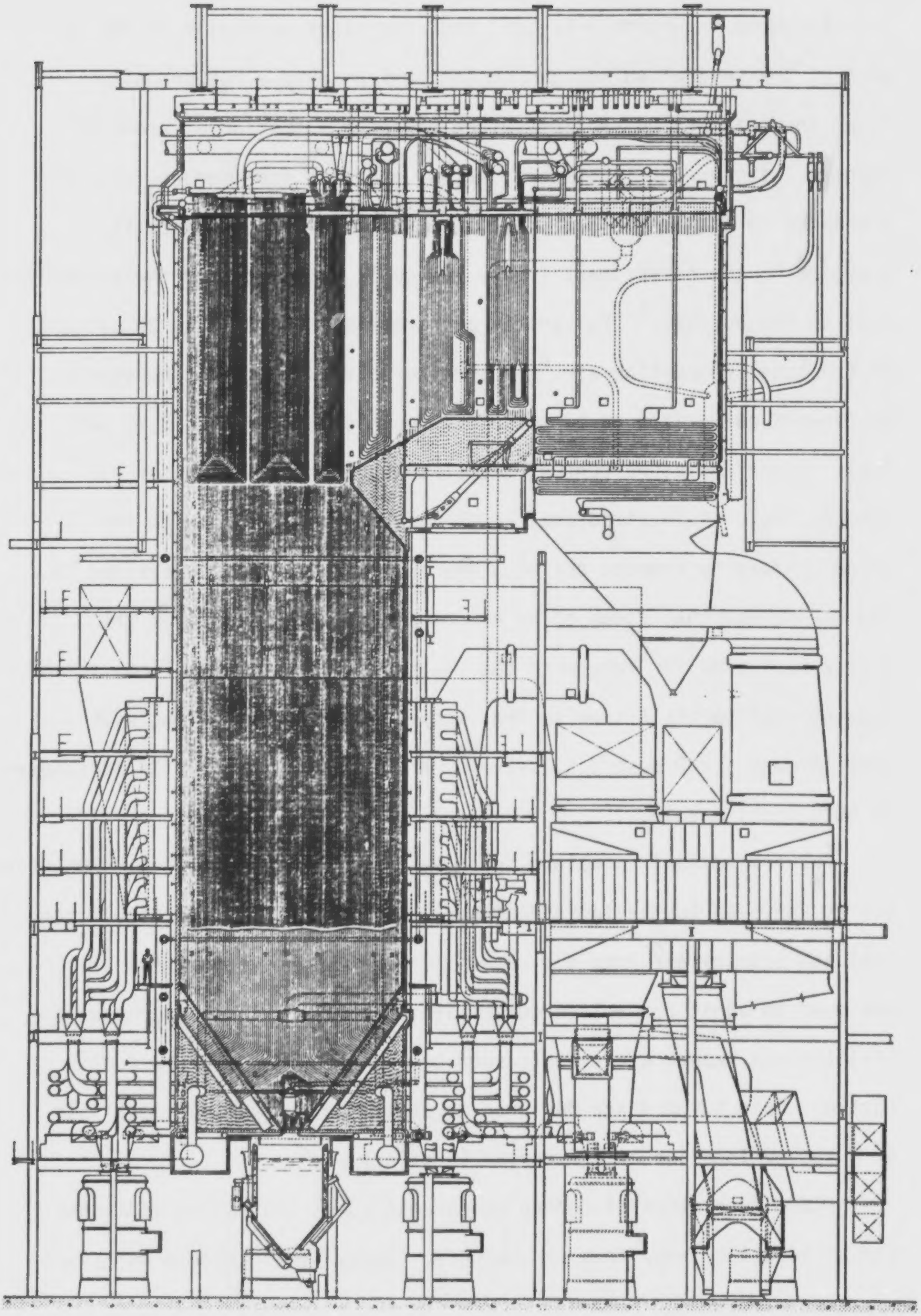

Figure 3-4

TANGENTIALLY FIRED BOILER

As shown in Figure 3-5, coal from the plant stockpile is fed to each of the several pulverizer systems which serve a boiler unit. Often there is one pulverizer system for each elevation or group of burners, with one or more spare systems provided for emergencies. Air preheated to as much as 315°C (600°F) by the combustion gases is supplied to the pulverizers to dry the coal, and to convey the pulverized fuel to the burners.[6] Pulverizer air comprises about 15 to 20 percent of the total combustion air.[6] Pulverizer air preheat is a necessity to prevent pulverizer or burner blockage which can be caused by wet fuel. Higher moisture content coals require hotter pulverizer air temperatures. Pulverized coal is recirculated and mixed with the incoming feed to promote drying. The pulverized coal is entrained in the air stream that flows to an air classifer which separates the larger particles for return to the pulverizer. The preparation system reduces coal particle size so that about 70 percent by weight will pass through a 200 mesh U.S. sieve.[6] A 200 mesh screen has 74 micrometer (0.0029 inch) openings.

Pulverized coal entrained in 15 to 20 percent of the total combustion air is conveyed to the individual burner fuel nozzles which direct the coal and primary air into the combustion chamber.[6] The burners are designed to admit controlled quantities of additional air (secondary air) through separate air ports surrounding or built into the fuel nozzle. Some burners are designed to admit controlled additional air at a second location at the burner (tertiary air).

Steam generators of modern design can admit controlled additional air at locations away from the burners. Riley Stoker modern units are

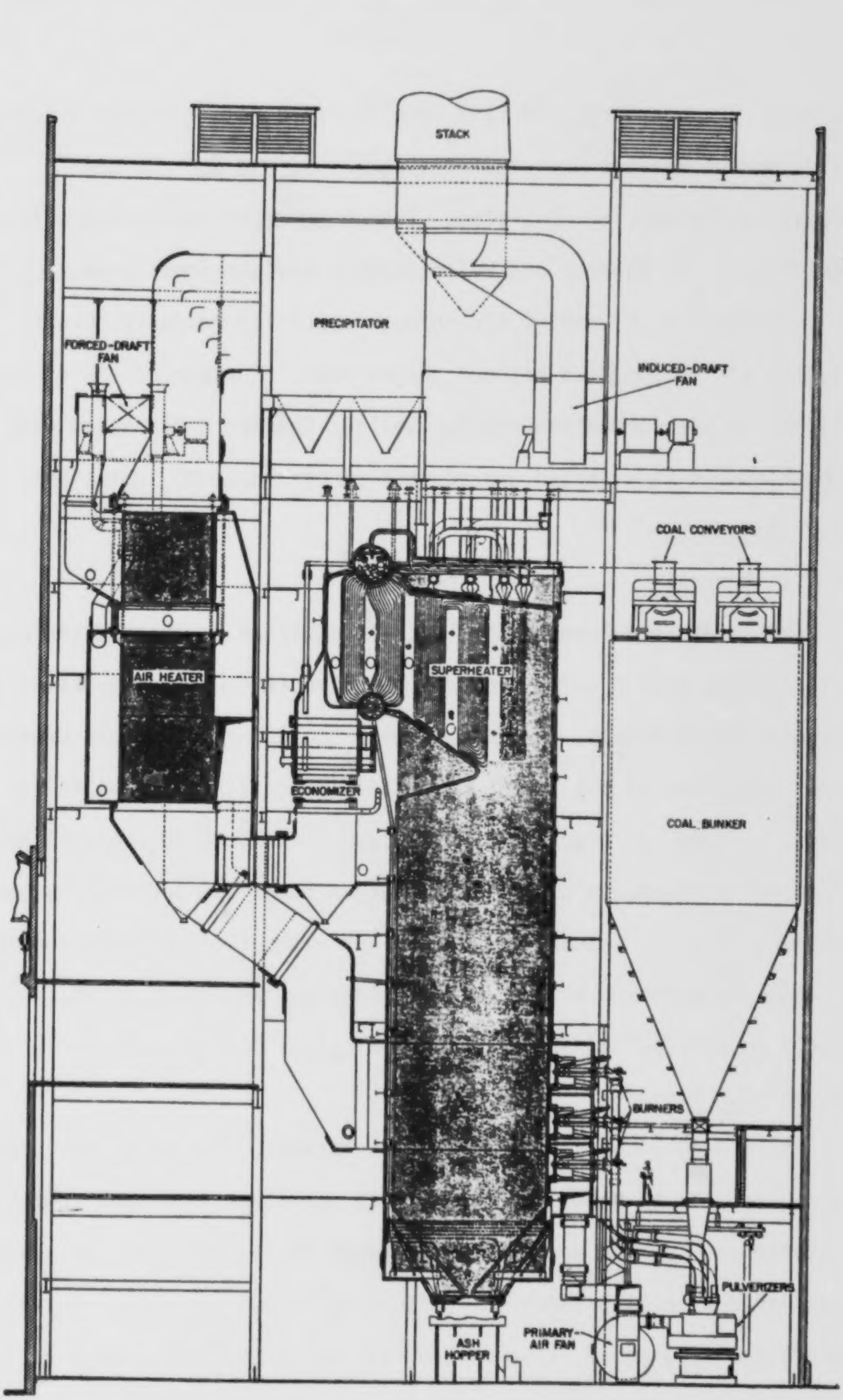
STACK
PRECIPITATOR
FORCED-DRAFT FAN
INDUCED-DRAFT FAN
COAL CONVEYORS
AIR HEATER
SUPERHEATER
ECONOMIZER
COAL BUNKER
BURNERS
PULVERIZERS
PRIMARY-AIR FAN
ASH HOPPER

Figure 3-5

Typical pulverized coal fired boiler

equipped for underfire, sidefire, and overfire air.[8] Foster Wheeler builds modern designs for sidefire, overfire, and curtain air.[9] Combustion Engineering coal-fired steam generators are equipped for overfire air.[10] Babcock and Wilcox modern designs admit combustion air as primary or secondary air through specially designed burners.[11] Sidefire air is admitted between burner rows. Curtain air is directed parallel to the combustion chamber walls. Chapter 6 discusses how combustion air is directed and controlled to reduce NO_x emissions.

3.2.2 Emissions

3.2.2.1 General

Emissions from large fossil fuel-fired steam generators include particulates, sulfur oxides, oxides of nitrogen (NO_x), carbon monoxide, halogens, trace metals, and hydrocarbons including polycyclic organic matter. NO_x control has little potential or actual effect on sulfur oxides, halogen, or trace metal emissions. Although NO_x control has a tendency to increase particulate, carbon monoxide, and hydrocarbon emissions, NO_x can actually be controlled without significant increases in these pollutants (see Chapter 6). Data on the effect of NO_x control on polycyclic organic matter emissions is given in Chapter 6.

3.2.2.2 NO_x Emissions

Table 3-10 gives a summary of 1976 estimated NO_x emissions from all sources.[16] As shown, estimated 1976 emissions from fuel combustion in stationary sources were 11.8 teragrams (13.1×10^6 tons) per year as compared with 23.0 teragrams (25.5×10^6 tons) per year from all sources and were about 51 percent of all NO_x emissions. Table 3-11 shows estimated 1976 NO_x emissions from fossil fuel combustion sources.[16]

As shown, estimated 1976 NO_x emissions from the large fossil fuel-fired steam generators used by the electric utility industry were about 6.67 teragrams (7.35 x 10^6 tons) per year as compared with about 8.71 teragrams (9.60 x 10^6 tons) per year from all fossil fuel-fired sources. Estimated 1976 electric utility NO_x emissions were about 77 percent of total stationary source fossil fuel combustion NO_x emissions and were about 29 percent of 1976 NO_x emissions from all sources.

TABLE 3-10

SUMMARY OF 1976 NATIONWIDE NITROGEN OXIDES EMISSIONS[16]
BY SOURCE CATEGORY

	NO_x Emissions Teragrams Per Year (10^6 Tons/Yr)
Transportation	10.1 (11.2)
Stationary Source Combustion	11.8 (13.1)
Industrial Processes	0.7 (0.8)
Solid Waste Disposal	0.1 (0.1)
Other	0.3 (0.3)
Total	23.0 (25.5)

TABLE 3-11

SUMMARY OF 1976 NATIONWIDE NITROGEN OXIDES EMISSIONS[16] FROM STATIONARY FOSSIL FUEL COMBUSTION SOURCES

NO_x Emissions = Teragrams Per Year (10^6 Tons/Yr)

	Coal	Oil	Gas	Total
Electric Utilities	4.82 (5.31)	1.06 (1.17)	0.79 (.87)	6.67 (7.35)
Industry Except Light Industry	0.54 (0.59)	0.27 (0.30)	0.55 (0.61)	1.36 (1.50)
Residential-Commercial and Light Industry	0.03 (0.03)	0.31 (0.34)	0.34 (0.38)	0.68 (0.75)
Total	5.39 (5.93)	1.64 (1.81)	1.68 (1.86)	8.71[a] (9.60)

[a] Does not include gas turbine emissions

Table 3-12 gives NO_x emission factors for dry ash, slag tap, and cyclone type large coal-fired steam generators.[17] Emission factors are intended for use when emission test data is not available.

TABLE 3-12

EMISSION FACTORS FOR COAL-FIRED STEAM GENERATORS[17] OF THE ELECTRIC UTILITY INDUSTRY

	Emissions		
Boiler Type	Grams Per Kilogram (lb/ton)	Nanograms[(a)] Per Joule (lb/10^6 Btu)	Estimated PPM[(a) (b)] 3 Percent O_2 Dry
Dry Ash (Dry Bottom)	9 (18)	320 (0.75)	540
Slag Tap (Wet Bottom)	15 (30)	540 (1.25)	900
Cyclone	27.5 (55)	980 (2.29)	1640

(a) Coal calorific value of 27.900 megajoules per kilogram (12,000 Btu/lb)

(b) 263.36 dry, standard cubic millimetres per joule (9820 DSCF/10^6 Btu). Estimated per method of Subpart D, Part 60, Subchapter C, Chapter 1, Title 40, Code of Federal Regulations.

As shown by Table 3-12, NO_x emissions are characteristically greater from cyclone units than from any other firing configuration and are usually greater from slag tap units than from dry ash units. NO_x emissions tend to be greater from single wall-fired units than from horizontally opposed-fired units and tend to be the least from tangential-fired units.[18] An increase in the total steam generating capacity of a unit also tends to increase NO_x emissions. However, no quantitative values are assigned to the foregoing differences.

As discussed in Chapter 6, NO_x emissions from any given coal-fired steam generator design can vary widely depending on the way the way the unit is operated.

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4. NO_x CONTROL TECHNOLOGY FOR PULVERIZED COAL (EXCEPT LIGNITE)-FIRED STEAM GENERATORS

4.1 CONTROL PRINCIPLES FOR NO_x

NO_x forms via two distinct mechanisms; one in which elemental nitrogen is taken from the air and the other in which chemically combined nitrogen is taken from the fuel.

Fixation of nitrogen of the air can be limited by reducing the level of thermal excitation due to the flame temperature thereby minimizing the Zel 'dovich reactions:

$$O_2 + M \rightarrow O + O + M$$

$$O + N_2 \rightarrow NO + N$$

$$N + O_2 \rightarrow NO + O$$

where M represents the hydrocarbons in the flame.[1] Thermal excitation can be reduced by (a) flue gas recirculation, (b) staged combustion, (c) water or steam injection, (d) reduced air preheat, or (e) reduced heat release rate.

Oxidation of fuel nitrogen may be responsible for as much as 80-90 percent of the total NO_x emissions from pulverized coal firing.[2] Reactions between fuel nitrogen and oxygen are retarded by burning as much of the fuel as possible in an oxygen deficient atmosphere.[2] This is accomplished by limiting the combustion air supplied at or near the burners and by directing the air to limit high temperature mixing of volatilized fuel nitrogen and air. When the fuel nitrogen is volatilized in the absence of air and at high temperature, most of the nitrogen which is part of hydrocarbon molecules is reduced to molecular nitrogen.[2] Further NO_x formation is limited to that formed by fixation of nitrogen in the air according to the Zel 'dovich reactions.[1]

The oxygen deficient conditions which limit NO_x formation from reactions between fuel nitrogen and oxygen are poor conditions for complete fuel oxidation. Consequently, there must finally be intimate contact between combustibles and oxygen before the gases leave the furnace. This is accomplished by surrounding the fuel rich flame with an air rich zone. As the fuel rich gases cool by radiating thermal energy to surrounding colder surfaces, the gases flow into the air rich zone and combustion is completed at temperatures less favorable for NO_x formation. This is known as staged combustion. As discussed in Section 4.3, staged combustion is accomplished in more than one way.

Table 4-1 summarizes NO_x control methods. In Sections 4.3, 4.4, and 4.5 of this chapter,the most viable control methods are discussed. More data on control methods are given in Chapter 6.

4.2 CONTROL METHODS FOR PULVERIZED COAL-FIRED UTILITY BOILERS

Because of very high efficiency losses, water injection and reduced combustion air preheat are not competitive NO_x control methods for utility boilers. Flue gas recirculation is ineffective for controlling fuel NO_x from coal.[3] Control of coal nitrogen content is not practical because the nitrogen content of most coals is in a narrow range between 1.2 and 2.1 percent.[4] Although some stack gas cleaning systems have

TABLE 4-1. NO_x CONTROL METHODS FOR FOSSIL FUEL-FIRED UTILITY BOILERS[3]

Category	Method	NO_x Reduction			Other Aspects to be Considered for Utility Boilers
		Gas	Oil	Coal	
Prevention of Thermal NO_x	Flue gas recirculation	60%	20%	Not effective	More costly ducts, fans
	Reduced preheat	50%	40%	Not effective	Boiler efficiency loss
	Steam or Water Injection	60%	40%	Not effective	Boiler efficiency loss, costly pumps
Prevention of Thermal NO_x and Fuel NO_x	Staged combustion	55%	40%	40%	Requires either some burners idled or inlets for overfiring
	Low excess air	20%	20%	20%	Poor fuel burn out, ash fouling, increased tube wastage
	Reduced heat release rate	20%	20%	20%	Requires larger boiler
	Combined staging, low excess air, and reduced heat release	50%	35%	40%	Same as above, combined
Prevention of Fuel NO_x	Change to fuel with lower % N	Not effective	40%	20%	Fuel with lower % N may be costly

been applied to combustion sources in Japan, experience with NO_x gas cleaning systems for pulverized coal-fired sources is so limited that this technique currently is not considered an adequately demonstrated NO_x control alternative for new source performance standards.[5] Therefore, the control methods of Table 4-1 to be considered in further detail for pulverized coal are:

- Staged Combustion
- Low Excess Air
- Reduced Heat Release Rate
- Combined Techniques

4.3 STAGED COMBUSTION

A typical utility boiler operates with an array of burners, each of which operates with a flame "basket" of overall excess air equal to the total excess air of the entire boiler. As discussed in Chapter 6, the flame characteristics differ for individual boiler manufacturer's designs. Staged combustion is accomplished by redistributing the air flow such that a cooler secondary combustion zone is encountered by the combustion gases after they leave the flame basket. Staged combustion has two effects on NO_x:

1. Fuel NO_x is reduced because less oxygen is available during volatilization.
2. Thermal NO_x is reduced because the temperature does not reach as high a peak as when all the heat release occurs in one stage.

Two methods of air redistribution are shown schematically in Figure 4-1. Starting from the normal air/fuel ratio at the burners, staging can be accomplished either by maldistributing air (overfire air port), or by maldistributing fuel (burner out of service.). The extent of staged air can be conveniently indexed by the fraction of stoichiometrically-required air remaining at the burner flame baskets. For example, suppose a boiler operating with 15 percent excess air has five operating burner levels with air supplied to six levels. Then one-sixth of the air supply is staged, leaving the burners (115 x 5/6) or 95 percent of stoichiometric air at the burners. This type of staged combustion has shown reductions of 20-40 percent when applied to pulverized coal-fired utility boilers.[3]

Staged combustion conditions can also be created by special burner designs. Figure 4-2 shows the burner used by one of the four major utility boiler manufacturers. The burner produces a lazy, fuel-rich flame surrounded by an air envelope. Limited testing indicates that the burner can reduce NO_x emissions by as much as 50 percent.[6,7]

4.4 LOW EXCESS AIR

In addition to the air needed to complete combustion, about 10 to 20 percent excess air is added to utility boilers to cover normal ± 3 percent fluctuations in excess air and to aid soot burnout.[8]

At times excess air is needed to increase convective heat transfer, to cool the slag below the softening point, or to minimize tube wastage (corrosion).[9,10,11,12] The foregoing factors are discussed in Chapter 6. Subject to these operating constraints, if excess air can be minimized then NO_x is reduced for two reasons:

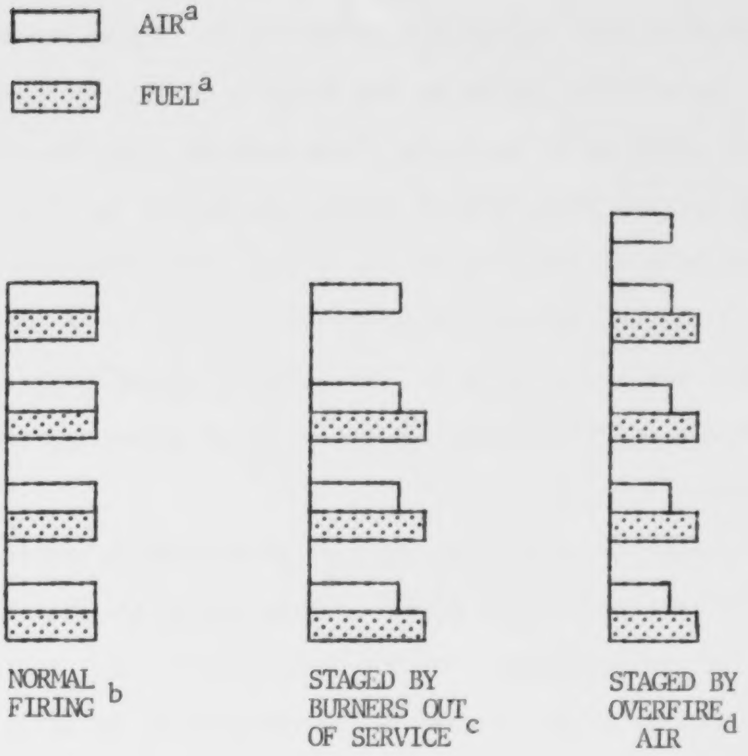

AIR[a]
FUEL[a]
NORMAL FIRING[b]
STAGED BY BURNERS OUT OF SERVICE[c]
STAGED BY OVERFIRE AIR[d]

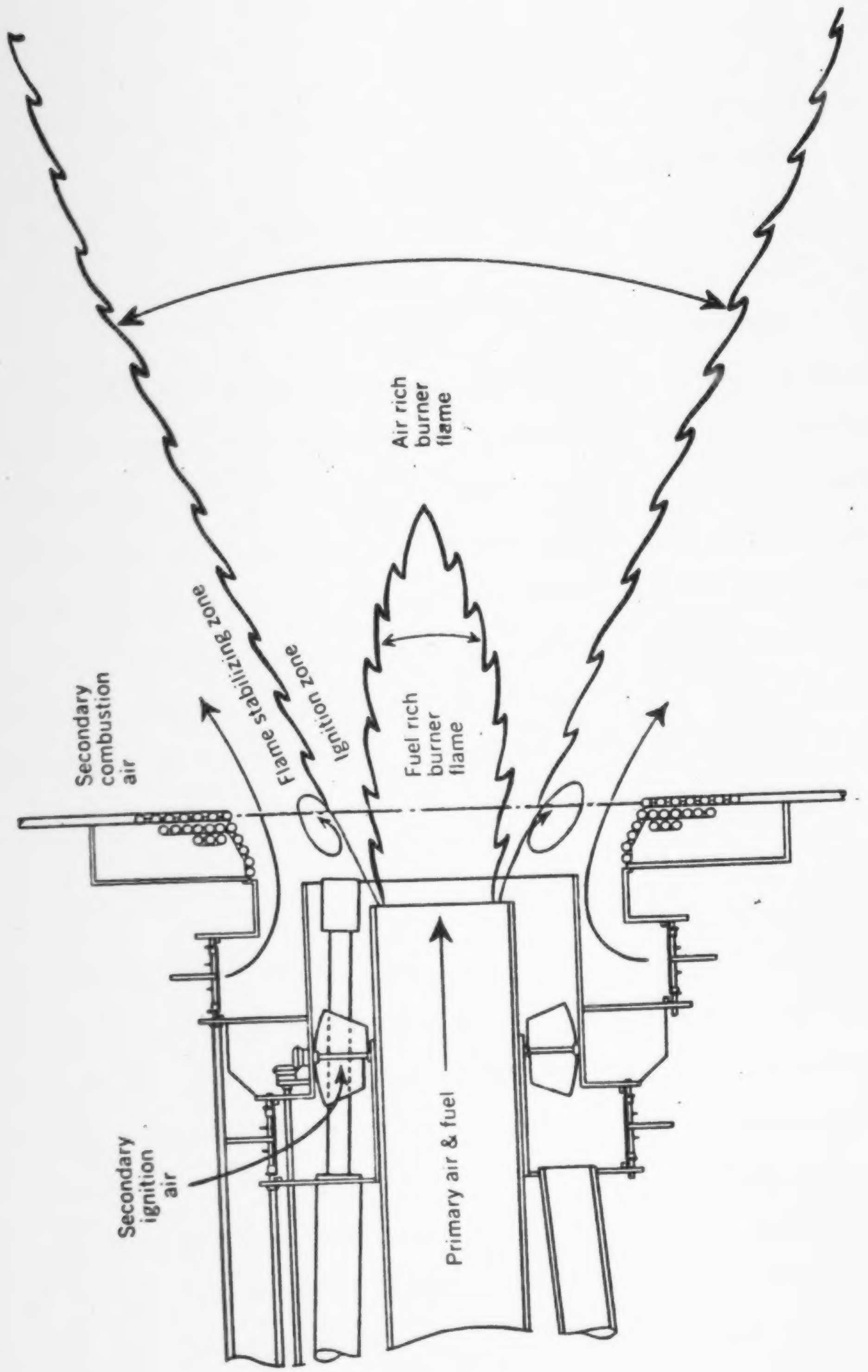
Figure 4-1. Variations in firing techniques for staged combustion of NOx emissions from existing units.

[a] Length equals proportionate quantities of fuel and air.

[b] All levels of burners firing fuel.

[c] No fuel fired on upper burner levels.

[d] All levels of burners firing fuel, overfire air added.


Secondary combustion air
Flame stabilizing zone
Ignition zone
Fuel rich burner flame
Air rich burner flame
Secondary ignition air
Primary air & fuel

Burner principles for low No$_x$ emissions

Figure 4-2

1. Fuel NO_x is reduced because less oxygen is available during volatilization.
2. Thermal NO_x is reduced because the controlling Zel 'dovich reaction, $O + N_2$ NO + N, is retarded by low oxygen radical concentrations.

It should be noted that under ideal conditions, well mixed, adiabatic combustion systems respond adversely to lower excess air, giving higher NO because of higher adiabatic flame temperature.[13] However, in reality, utility boiler systems usually show NO_x reduction with low excess air.[3] Emission of NO_x from coal-fired boilers as a function of excess air are shown in Figure 4-3.[3] As shown, the effectiveness of reduced excess air varies for individual boilers. As discussed in Chapter 6, the test conditions shown in Figure 4-3 may not be suitable for long term operations because of fuel burnout, slagging, carbon monoxide, or tube wastage (corrosion) problems.

4.5 REDUCED HEAT RELEASE RATE

Emission of NO_x is also limited by reducing heat release rate. Prior to the Federal New Source Performance Standards for NO_x promulgated in 1971, all four major boiler manufacturers were reducing combustion chamber size in relation to firing rate, thereby increasing heat release rates.[9,10,11,12] As a result of the 1971 standards, all four manufacturers decided to use more conservative design criteria which resulted in increases in combustion chamber size ranging from 15 to 50 percent. Reducing heat release rate reduces combustion gas temperatures more rapidly, thereby reducing the rate and mass of formation

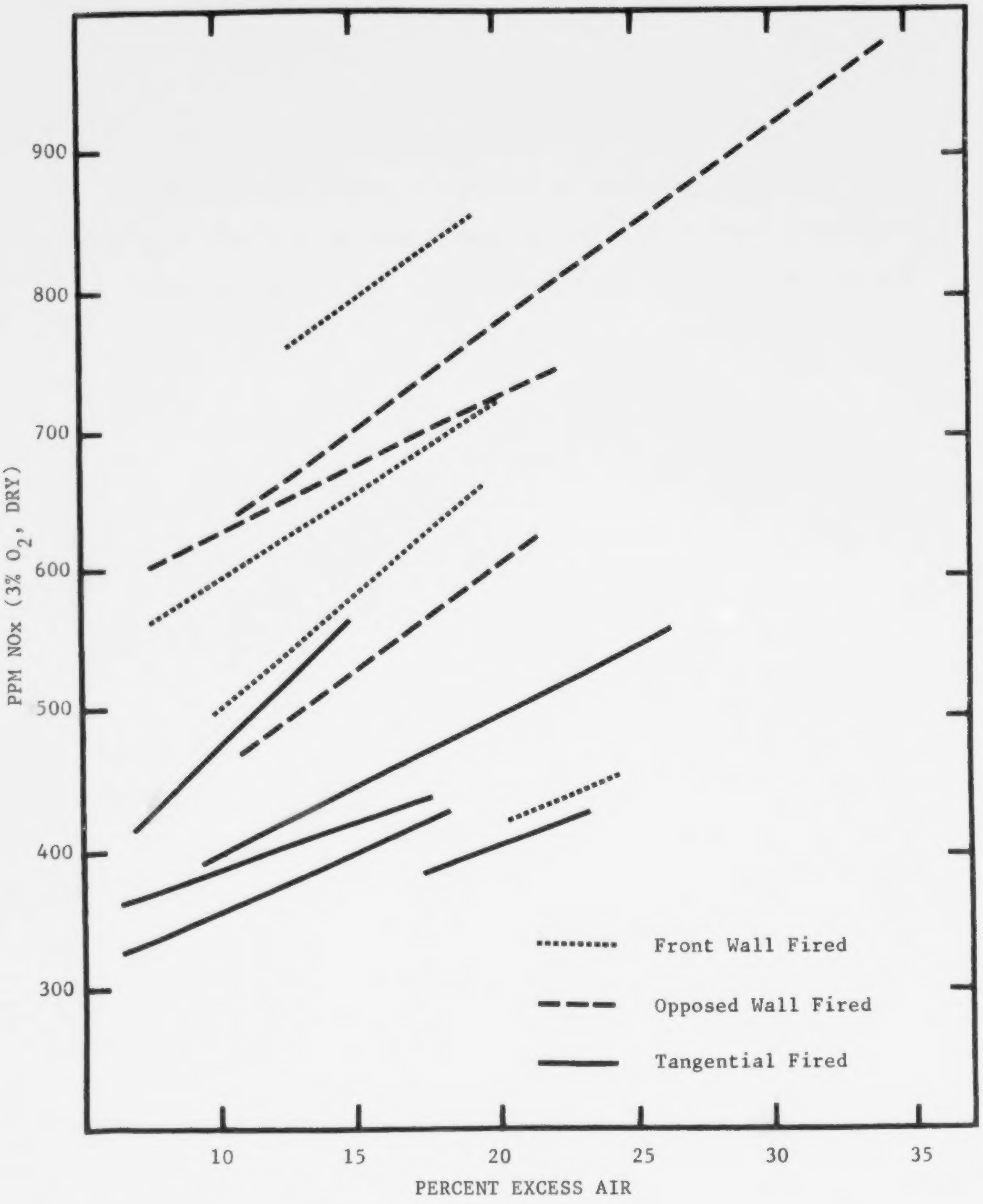


Figure 4-3 Relationship between PPM NOx and percent excess air for selected coal-fired boilers.[3]

of NO_x from the reactions between the nitrogen of the combustion air and oxygen.

4.6 COMBINED TECHNIQUES

The most effective, viable NO_x control technique for pulverized coal-fired steam generators is to employ a combination of staged combustion, lower excess air, and reduced heat release rate techniques. Chapter 6 discusses the various techniques used by the four major boiler manufacturers.

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5. MODIFICATION AND RECONSTRUCTION

5.1 GENERAL

The terms modification and reconstruction have special meanings when used in new source performance standards. These terms are clarified in Subpart A, Part 60, Subchapter C, Chapter 1, Title 40, Code of Federal Regulations. In general terms, a modification is a selected type of change which increases the emission of selected pollutants to the atmosphere. When the alterations are limited, new source performance standards only require that increases in the emission of selected pollutants be prevented. In general terms, reconstruction is a change which is so substantial as to class the source as a new source rather than an altered existing source. In this case, the source becomes subject to all the limits of the new source performance standard.

5.2 MODIFICATION

5.2.1 Scope and Effect of Modifcation Regulations

A modification means any change in the method of operation of an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted. The term modification is further limited by exempting selected types of changes from the applicability of new source performance standards.

Normally, all that is required of an existing facility is that emissions of a specific pollutant after alteration be no more than they were before alteration. These modification regulations only apply to the pollutants of the new source standard and apply on a pollutant-by-pollutant basis. In rare cases, emission of one or more pollutants may be less than the limit of a new source performance standard prior to the alteration. In this situation, an emission increase is allowed, up the limit of the applicable new source performance standard. Consequently, when changes are made which cause an existing source to become subject to a new source performance standard, emission control systems are normally altered to prevent emission increases. In exceptional circumstances, no additional air pollution control equipment may be needed to prevent an emission increase or; limiting emissions to the level of the new source performance standard may be less costly than preventing an emission increase.

Adding an affected facility to a plant or replacing an existing facility within a plant would not cause other unchanged existing facilities within the plant to become subject to the no emission increase rule. Where a plant has several existing facilities, the no emission increase rule may not apply to an altered existing facility if net plant emissions are not increased. For example, if emissions of pollutant A are increased by a change to facility 1 in a plant, this emission increase is allowed if emissions of pollutant A from facility 2 are decreased by an amount equal to or exceeding the amount of increase from facility 1.

Emission increases are allowed if such increases are caused by routine maintenance, repair, and replacement. Emission increases are also allowed if caused by increases in production rate which can be accomplished without major capital expenditure. Increases in emissions caused by longer operating hours are also exempted from the rule on no emission increase. Another exemption is for the use of an alternative fuel or raw material if--prior to the date any standard becomes applicable--the existing facility was designed to accommodate that alternative use. Conversion to coal as stipulated in Section 111(a)(8) of the Clean Air Amendments of 1977 is not considered a modification. Emission increases caused by the addition or use of any system whose primary function is the reduction of air pollutants, are also exempt from the no emission increase rule.

5.2.2 Modified Pulverized Coal-Fired Steam Generators

For the purposes of determining if modification regulations apply or should apply, the pulverized coal-fired steam generator system is defined as including the following major components.

a) pulverizer system
b) combustion air system
c) steam generation system
d) draft system
e) fuel combustion system

The major points which define the inlets to the affected facility are:

1. The inlet to the pumps which feed water at steam generator pressure.
2. The inlet to the bins which directly feed the pulverized or stoker systems unless the bins are sized to store more than enough coal to operate the steam generator 72 hours at full load. When large bins are installed, the inlet to the affected facility is the outlet of the bins feeding the pulverizer or stoker systems.
3. The combustion air intakes.

The major points which define the outlets of the affected facility are:

1. Any steam outlet
2. Any bottom ash outlet
3. The outlet of the last system installed before the stack, such as the outlet of any induced draft fan.

All components of the steam generator installed between these points are part of the affected facility except any air pollution control systems, such as electrostatic precipitators, mechanical collectors, baghouses, or scrubbers.

Replacement of the pulverizer system with a similar system or replacement of component parts of the pulverizer system with similar parts would not be considered a modified source. However, replacement or redesign of the pulverizer system which would substantially change the physical characteristics of the pulverized coal may be a change where modification regulations apply.

Likewise changes in the design of the combustion air system which change the way combustion air is introduced to the combustion chamber would cause a source to be evaluated to determine if modification regulations should apply. Changing the combustion air damper settings is not a modification as long as no redesign of the combustion air system is involved.

The steam generation system includes the feedwater treatment system, watertubes, economizer, and superheat and reheat sections. Maintenance of these components is not a modification. Major redesign of these parts would cause a source to be evaluated to determine if modification regulations should apply. It is doubtful that redesign of the feedwater treatment system, the economizer, or the superheat or reheat sections would affect NO_x emissions. Redesign of the steam generation system components which affect combustion temperatures--such as the waterwall sections--could change NO_x emission characteristics.

Redesign of the draft system such as changing from induced draft conditions to pressurized firing conditions would cause a source to be evaluated to determine if modification regulations should apply.

Changes in the fuel combustion system which would be modifications are:

a) changes in the number of burners

b) changes in the type of burners

and c) changes in the location of burners.

Although a change to a different nitrogen content or a different moisture content coal or a switch from lignite to non-lignite coal might be considered a modification, these changes are exempted from modification evaluation by current regulations.[1]

Sources, which by reason of the date of new construction, are subject to the NO_x new source performance standard for coal combustion continue to be subject to the original standard in spite of any subsequent changes in solid fossil fuels or alteration. In cases where the original NO_x standard is revised to become more restrictive, none of the foregoing discussed modifications should cause the source regulated by the original NO_x standard to become subject to the more restrictive standard unless the modifications are so extensive as to be classed as reconstruction. (See Section 5.3).

5.2.3 Modification of Oil- or Gas-Fired Steam Generators to Fire Coal

The discussion of Section 5.2.3 is limited to modifications which would cause a source to become subject to NO_x new source performance standard modification regulations for large pulverized coal (other than lignite)-fired steam generators.

Alterations which might cause an existing oil or gas-fired steam generator to become subject to NO_x modification regulations for coal-fired steam generators are alterations involving a switch from gas or oil to coal. Current regulations provide that if the oil or gas-fired source is already designed to fire coal, a switch to coal does not cause the source to become subject to coal-fired steam generator NO_x modification regulations. In addition, Section 111(a)(8) of the Clean Air Amendments of 1977 exempts from the modification provisions of the

Amendments certain sources switching from oil or gas to coal. This latter category of sources is described in general terms as sources required to switch to coal under Section 2(a) of the Energy Supply and Environmental Coordination Act of 1974. (The reader is cautioned to seek competent legal advice--such as from the Office of Enforcement and General Counsel, U. S. Environmental Protection Agency, Washington, D.C.--before assuming that a source switching from oil or gas to coal is exempted from the modification provisions of the Clean Air Amendments.)

Sources switching from oil or gas to coal which are not otherwise excepted by U. S. Environmental Protection Agency regulations or by law would be subject to NO_x new source performance standard modification regulations. Because oil and gas-fired steam generators characteristically emit less NO_x than coal-fired steam generators, a switch from oil or gas to coal would normally increase NO_x emission concentrations. However, the total rate of NO_x emissions might not be increased, because when steam generators which are originally designed for oil or gas firing and are not designed for coal firing are converted to fire coal, it is usually necessary to substantially reduce steam generator capacity and heat input. Consequently, altering an oil or gas-fired steam generator to fire coal may not increase the mass of NO_x emissions even if there is an increase in NO_x emission concentrations. Subpart A, Part 60, Subchapter C, Chapter 1, Title 40, Code of Federal Regulations, describes the procedure for determining if an NO_x emission increase has occurred.

The cost of modifying an oil or gas-fired steam generator to fire coal may be so substantial as to class the source as a reconstructed source (see Section 5.3).

Rulings on whether alterations of fossil fuel-fired steam generators constitute a modification can be obtained by contacting a U. S. Environmental Protection Agency Regional Office of Enforcement.

5.3 RECONSTRUCTION

The purpose of reconstruction regulations is to prevent the perpetuation of existing sources. When modifications or replacements become so extensive as to create an essentially new source, the source becomes a reconstructed source and is subject to the new source performance standards which apply at the time of initiation of reconstruction.

According to the provisions of Subpart A, Part 60, Subchapter C, Chapter 1, Title 40, Code of Federal Regulations, a facility becomes a reconstructed source irrespective of any change in emission rate when

a) the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility and

b) it is technologically and economically feasible to meet applicable standards.

Rulings on whether changes to a fossil fuel-fired steam generator constitute reconstruction can be obtained by contacting a U. S. Environmental Protection Agency Regional Office of Enforcement.

REFERENCES FOR CHAPTER 5

1. Subpart A, Part 60, Subchapter C, Chapter 1, Title 40, Code of Federal Regulations.

6. EMISSION CONTROL SYSTEMS

6.1 GENERAL

The discussion of Chapter 6 is limited to pulverized coal-fired steam generators other than those firing lignite. A separate document has been prepared for pulverized lignite combustion.[1] Recommendations for the few stoker-fired units larger than 73 megawatts (250 $\times 10^6$ Btu/hr) heat input are being developed separately in conjunction with recommendations for smaller stoker-fired units.

There are four manufacturers who now construct nearly all of the new pulverized coal-fired steam generators. These manufacturers are Babcock & Wilcox Company, Combustion Engineering, Incorporated, Foster Wheeler Energy Corporation, and Riley Stoker Corporation. All are currently furnishing or are constructing units designed to meet the current Federal NO_x new source performance standard of 300 nanograms per joule (0.7 lb/10^6 Btu).[2,3,4,5,6]

As documented in this chapter, Combustion Engineering (CE) pulverized coal-fired steam generators are capable of limiting NO_x emissions to a level less than 210 nanograms per joule (0.5 lb/10^6 Btu) without any of the following adverse side effects if subbituminous coal is fired.

a) severe tube wastage (corrosion)

b) unmanageable slagging

c) loss of boiler efficiency

d) loss of particulate control efficiency

e) increased ash combustible content

f) increased carbon monoxide emissions

g) increased hydrocarbon or polycyclic organic matter emissions

or h) increased tubine blade wear or loss of power generating efficiency caused by low superheat temperature

If bituminous coal is fired, a safer lower limit of NO_x control for CE units is a level of 260 nanograms per joule (0.6 lb/10^6 Btu) because of the potential danger of tube wastage from reducing combustion gas atmospheres. (See Chapter 4).

Although it is not as well documented that Babcock and Wilcox, Foster Wheeler, and Riley Stoker units are equally effective, it is likely these three manufacturers are capable of furnishing units which will perform as well as Combustion Engineering units.

6.2 NO_x CONTROL TECHNIQUES FOR INDIVIDUAL BOILER MANUFACTURER

6.2.1 Babcock and Wilcox

Modern Babcock and Wilcox (B&W) pulverized coal-fired steam generators designed to meet the current new source performance standard for NO_x are equipped with burners which are specially designed to limit NO_x emissions. Figure 6-1 shows a cutaway of the special burner.[7] Figure 6-2 shows how the burner is designed to produce a lazy, fuel-rich flame surrounded by an air envelope.[7] The fuel-rich gases diffuse into the air-rich zone and are cooled by radiation and dilution. Babcock and Wilcox claim that the new burner design will permit furnaces to be

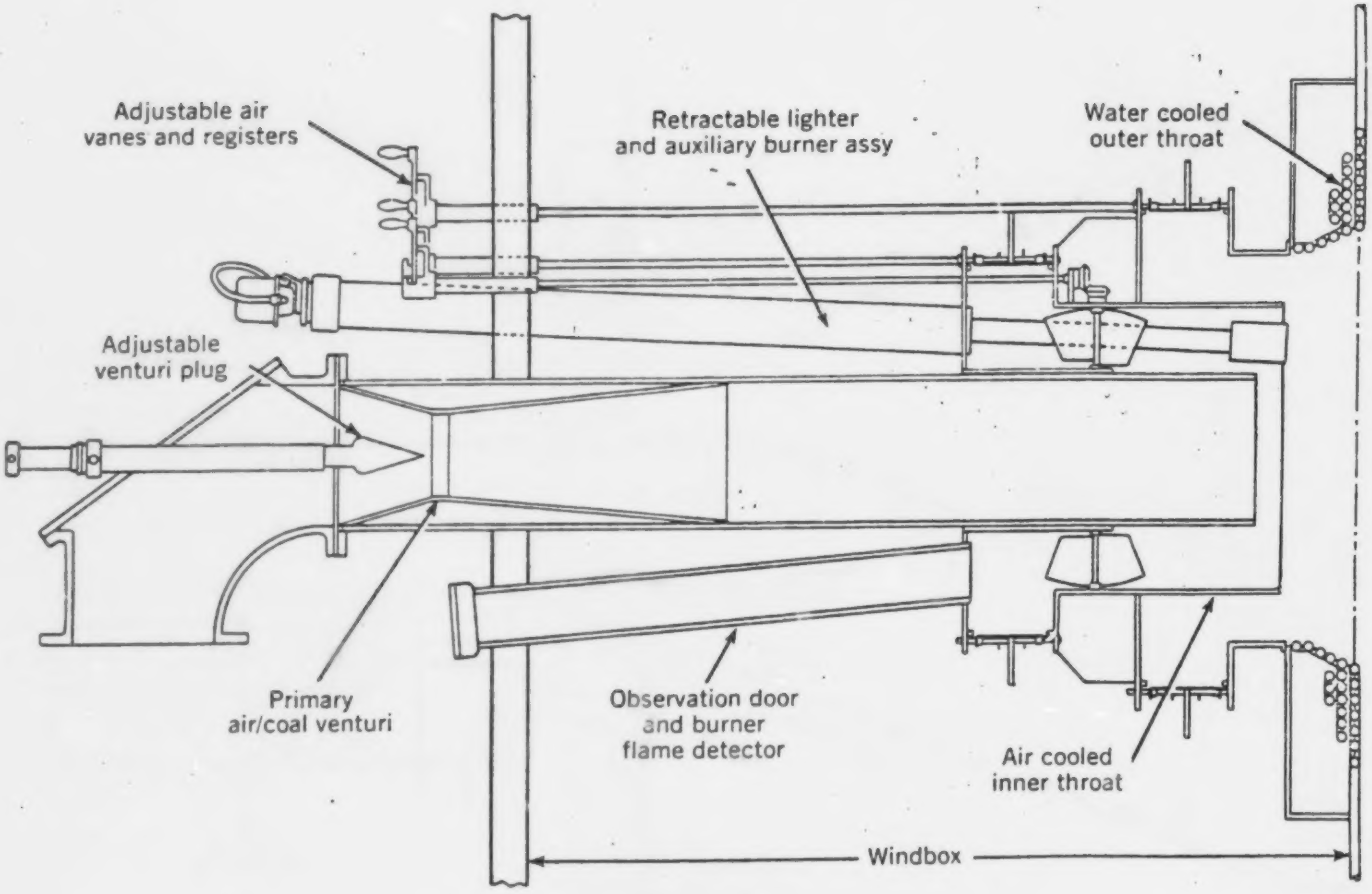
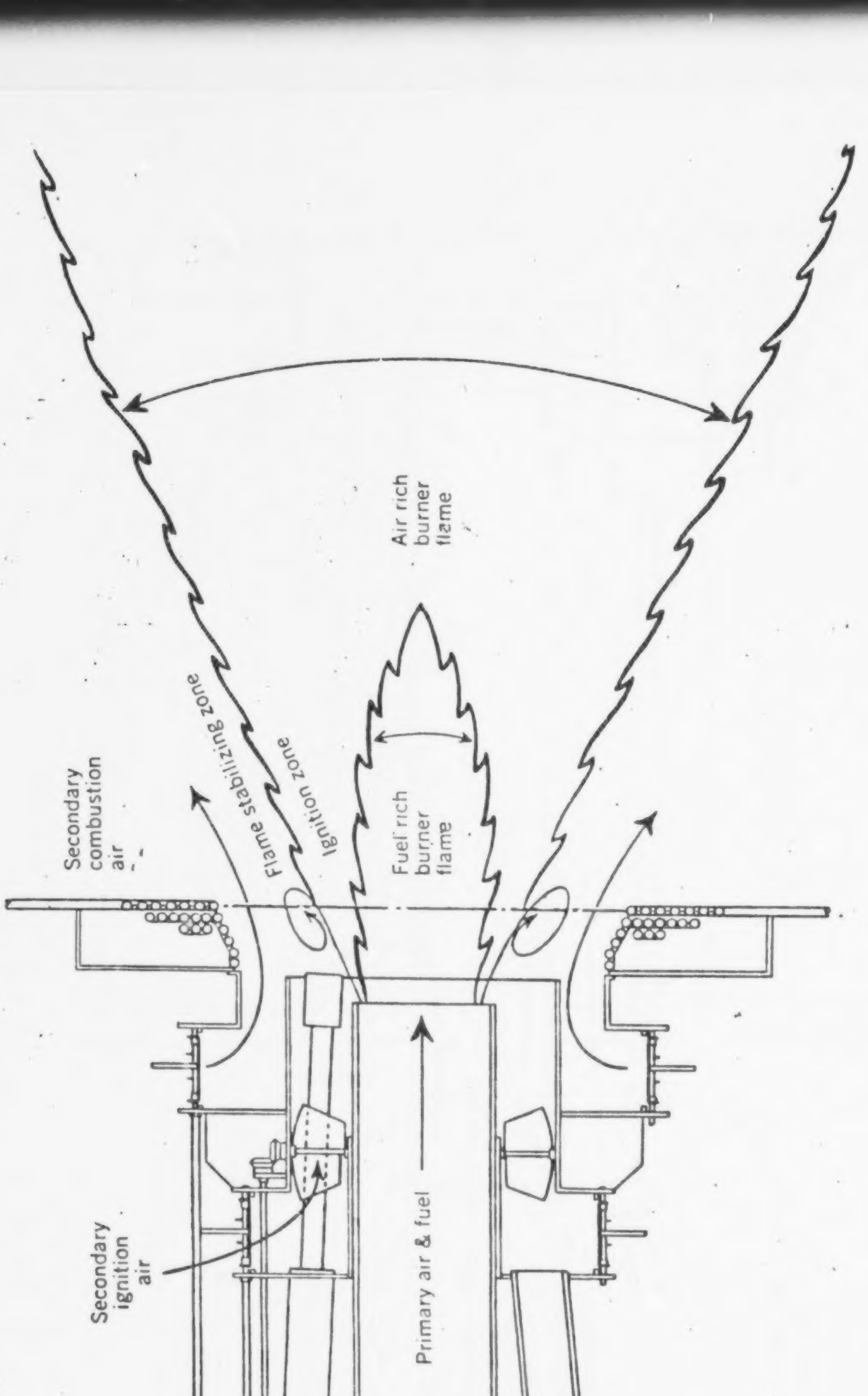

Adjustable air vanes and registers
Retractable lighter and auxiliary burner assy
Water cooled outer throat
Adjustable venturi plug
Primary air/coal venturi
Observation door and burner flame detector
Air cooled inner throat
Windbox

Figure 6-1

Dual register pulverized coal burner[7]


Secondary combustion air
Flame stabilizing zone
Ignition zone
Fuel rich burner flame
Air rich burner flame
Secondary ignition air
Primary air & fuel

Burner principles for low NO_x emissions[7]

Figure 6-2

maintained in an oxidizing environment, thus minimizing slagging and reducing the potential for furnace wall corrosion when high sulfur bituminous coal is burned.[8]

Comprehensive test data are available for a 270 megawatt unit (retrofitted), the first Babcock and Wilcox unit to be equipped with specially designed burners.[9] These burners are similar to, but are not identical with, the burners currently being furnished on modern Babcock and Wilcox pulverized coal-fired steam generators.

Table 6-1 shows full load NO_x emissions from the retrofitted boiler for a wide variety of operating conditions.[9] As shown, NO_x emission levels ranged from 167 to 233 nanograms per joule (0.39-0.54 $lb/10^6$ Btu) and were the lowest at oxygen contents less than 2.5 percent. Table 6-2 shows that boiler efficiency was about the same in the normal and low NO_x operating modes.[9] Fly ash carbon averaged 1.8 percent in the normal mode as compared with 4.4 percent in the low NO_x mode.[9] Table 6-3 shows that decreasing levels of oxygen may increase carbon monoxide concentrations while reducing emissions of NO_x.[9]

Table 6-4 compares corrosion test coupon weight losses for Boiler Nos. 1 and 2.[9] Boiler No. 1 is similar to Boiler No. 2 except that Boiler No. 1 is equipped with the modern specially designed B&W burners. Statistical analysis shows that test coupon losses for Boiler No. 1 (low NO_x) were significantly greater than test coupon losses for Boiler No. 2 (normal) when analyzed at the 95 percent confidence level.

Low NO_x operation of Boiler No. 1 of Table 6-4 did not cause any unmanageable slagging.[9] Superheat temperatures were maintained above design limits in the low NO_x mode.[9] There was no significant increase in particulate emissions.[9]

TABLE 6-1

Full Load NO_x Emissions from a 270 Megawatt[9] Babcock and Wilcox Pulverized Coal-Fired Steam Generator Retrofitted with Specially Designed Burners

Air Register Settings-Percent Open				
Secondary Air	Tertiary Air	Vanes	O_2 Percent By Volume	NO_x nanograms per joule ($lb/10^6$ Btu)
70	100	90	4.3	233 (0.54)
70	100	90	2.4	167 (0.39)
50	100	100	2.4	173 (0.40)
30	100	100	2.6	197 (0.46)
100	100	100	2.4	201 (0.47)
50	100	90	2.3	191 (0.44)
50	50	90	2.5	217 (0.51)
30	50	90	2.2	187 (0.44)
100	50	90	2.0	177 (0.41)

TABLE 6-2

Fly Ash Carbon, Efficiency, Oxygen, and NO_x at Full Load[9] for a 270 Megawatt Babcock and Wilcox Modern Design Pulverized Coal-Fired Steam Generator

Firing Mode	Carbon in Fly Ash % by Weight	Boiler Efficiency Percent	Oxygen Percent by Volume	NO_x Nanograms per Joule ($lb/10^6$ Btu)
Normal	2.7	89.8	4.2	350 (0.81)
Normal	1.1	90.1	4.2	350 (0.81)
Normal	1.7	89.9	4.1	343 (0.80)
Normal	2.1	89.2	4.3	363 (0.85)
Low NO_x	5.7	89.2	3.9	209 (0.49)
Low NO_x	3.4	89.6	3.9	189 (0.44)
Low NO_x	4.1	89.8	3.9	189 (0.44)

TABLE 6-3

Carbon Monoxide Emissions from a 270 Megawatt Babcock and Wilcox Modern Design Pulverized Coal-Fired Steam Generator at Various Oxygen, NO_x, and Load Levels[9]

Load Megawatts	Oxygen Percent by Volume	NO_x Nanograms per Joule (lb/10^6 Btu)	Carbon Monoxide ppm at 3 percent O_2
270	4.3	233 (0.54)	26
270	2.4	167 (0.39)	65
190	1.6	109 (0.25)	329

TABLE 6-4

Corrosion Test Data for Two Babcock and Wilcox[9] Pulverized Coal-Fired Steam Generators

Boiler No.	Probe No.	Firing Condition	Coupon Loss Micrometres per year (mils/year)
2 (old style)	3	Normal	262 (10.3)
2	3	Normal	185 (7.3)
2	3	Normal	259 (10.2)
2	4	Normal	203 (8.0)
2	4	Normal	160 (6.3)
2	4	Normal	152 (6.0)
Average			204 (8.0)
1 (Modern)	2	Low NO_x	508 (20.0)
1	2	Low NO_x	312 (12.3)
1	2	Low NO_x	264 (10.4)
1	1	Low NO_x	257 (10.1)
1	1	Low NO_x	180 (7.1)
1	1	Low NO_x	290 (11.4)
Average			302 (11.9)

Table 6-5 summarizes other test data on modern Babcock and Wilcox coal-fired steam generators.[8] As shown, controlled NO_x emissions ranged from 140 to 200 nanograms per joule (0.33-0.47 $lb/10^6$ Btu) showing that B&W coal-fired steam generators equipped with specially designed burners are capable of limiting NO_x emissions to low levels.[8]

TABLE 6-5

SUMMARY OF NO_x EMISSION CONTROL DATA FOR MODERN BABCOCK AND WILCOX COAL-FIRED STEAM GENERATORS EQUIPPED WITH SPECIALLY DESIGNED BURNERS

Plant No.	Plant Size MW	NO_x Emission Control Level Nanograms per joule ($lb/10^6$ Btu)
A[8]	90	142 (0.33)[a]
B[8]	250	202 (0.47)[a]
C[8]	700	150 (0.35)[a]

[a] Babcock and Wilcox Report. Test method not given.

Table 6-6 shows polycyclic organic matter emissions from an old style, horizontally opposed, 560 megawatt Babcock and Wilcox pulverized coal-fired steam generator.[10] The steam generator was operated with:

1. All burners in service
2. Selected burners on air only
3. Flue gas recirculation, all burners in service
4. Flue gas recirculation, selected burners on air only.

TABLE 6-6

SUMMARY OF POLYCYCLIC ORGANIC EMISSIONS FROM AN OLD STYLE BABCOCK AND WILCOX 560 MEGAWATT PULVERIZED COAL-FIRED STEAM GENERATOR[10]

Micrograms per Dry Standard Cubic Metre

	Baseline All Burners In Service	Staged Combustion Selected Burners Out of Service	15 Percent Flue Gas Recirculation All Burners In Service	15 Percent Flue Gas Recirculation Selected Burners Out of Service
Anthracene/Phenanthrene	178.4	179.3	145.3	230.4
Methyl Anthracenes	53.4	48.5	89.4	98.3
Fluoranthene	51.5	110.3	24.7	43.7
Pyrene	15.1	52.1	23.3	46.9
Chrysene/Benz (A) Anthracene	0.3	--	--	--
Total POM	298.7	390.2	282.7	419.3
Percent of Baseline	100	131	95	140

The data indicate that two stage combustion with selected burners out of service may increase polycyclic organic matter emissions from old Babcock and Wilcox steam generators equipped with old style burners. However, this data is insufficient to draw any conclusions on the effect of modern, low NO_x B&W burners on polycyclic organic matter emissions.

Babcock and Wilcox is now building a new unit which will be required to comply with the State of New Mexico emission limitation of 193 ng/J (0.45 lb/million Btu).[11] The unit will burn subbituminous coal with a heat content of about 22.6 kilojoules per kilogram (9700 Btu/lb) and a sulfur content of 0.9% by weight.[12] Construction is scheduled for completion in May, 1979. Babcock and Wilcox would not have contracted to furnish this multimillion dollar unit unless they were sure of their capabilities for designing a unit which would comply with the State of New Mexico NO_x regulation.

6.2.2 Combustion Engineering, Incorporated

Modern design Combustion Engineering (CE) pulverized coal-fired steam generators are much the same as the old style designs except modern units are equipped for overfire air and are 15 to 20 percent larger.[4] Figure 6-3 shows a cutaway of a modern design unit. The tangential design creates a swirling ball of fuel rich combustion gases in the firing zone surrounded by an air rich zone. As the gases diffuse toward the walls, they are cooled by radiation and dilution. With overfire air, less combustion air can be used in the firing zone without reducing total combustion air. This limits NO_x formation. The best full load NO_x emission control is achieved when the overfire air dampers

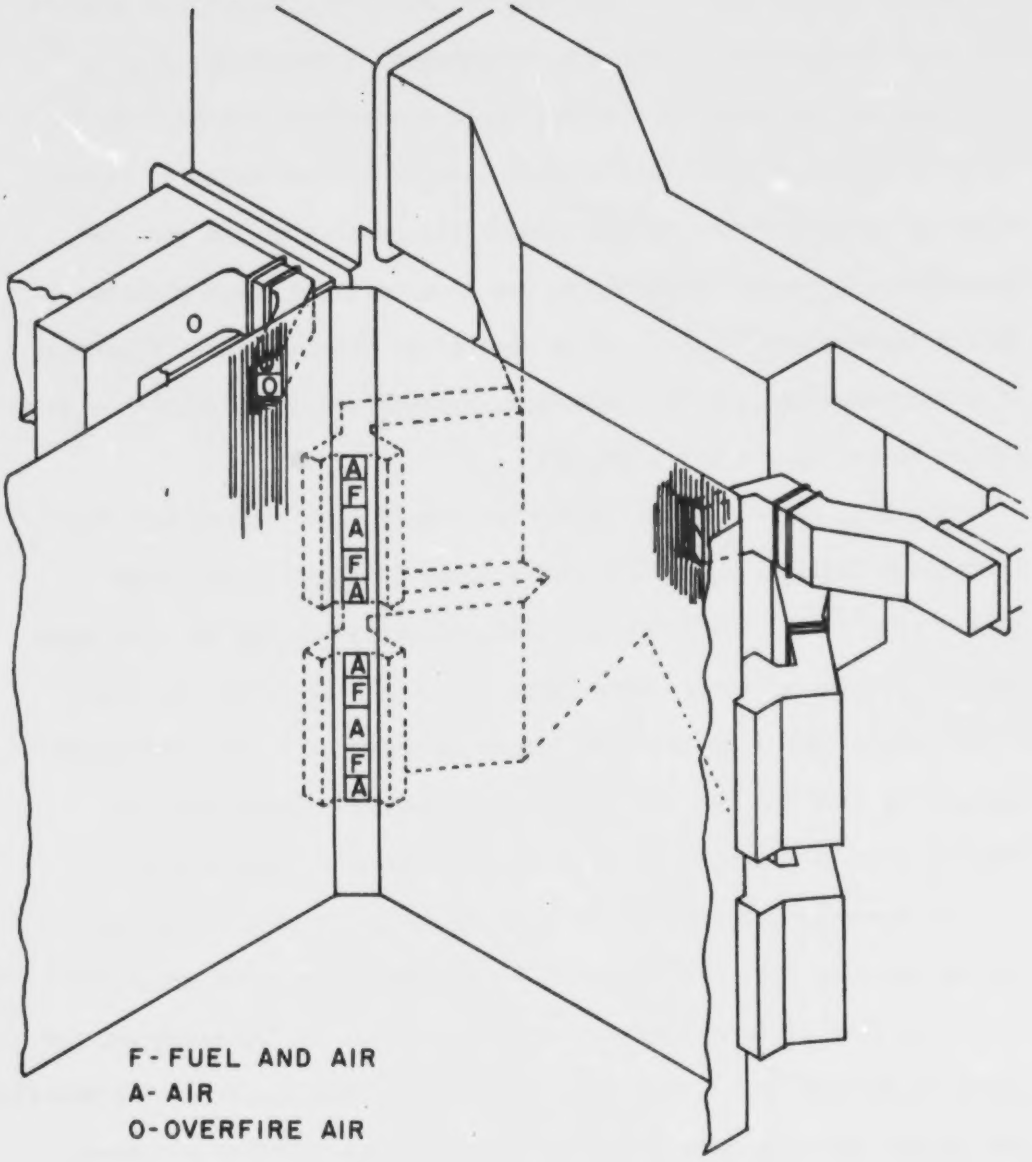

O
O
A
F
A
F
A
A
F
A
F
A
F-FUEL AND AIR
A-AIR
O-OVERFIRE AIR

Figure 6-3
Schematic Overfire Air System, Barry No. 2

are wide open.[9,13,14] Both old style and modern design tangential units are equipped with burners which can be tilted upward or downward.[4] The modern design units are equipped so that the overfire air nozzles can be tilted upward or downward independent of the burner nozzles.[4] By adjusting the overfire air nozzle and burner nozzle tilt, low NO_x emission levels are achieved without significant increases in carbon monoxide concentrations or the combustible content of the ash, and superheat and reheat temperatures can be maintained above minimum design temperature.[9,13,14] It is logical to conclude that if carbon monoxide emissions are not increased, hydrocarbon or polycyclic organic matter emissions are not increased.

The U.S. Environmental Protection Agency (EPA) has tested five Combustion Engineering modern design pulverized coal-fired steam generators.[9,13,14] In addition, Combustion Engineering has furnished EPA the results of eleven more tests of tangential pulverized coal-fired (other than lignite-fired) steam generators.[15] The Combustion Enginering data and the EPA data used to evaluate Combustion Engineering units are contained in or are referenced in Appendix C.

As shown in Table 6-7, full load NO_x emission levels measured during the five U.S. Environmental Protection Agency test projects involving five different sources ranged from 109 to 236 nanograms per joule (0.25-0.55 $lb/10^6$ Btu) when the sources were operated at combustion gas oxygen contents less than 5 percent and with overfire air damper settings at least 50 percent open.[9,13,14]

For all five units there was no significant difference between the fly ash carbon content during low NO_x and normal operations.[9,13,14]

Table 6-7

DATA ON TANGENTIAL PULVERIZED COAL-FIRED STEAM GENERATORS[9,13,14] TESTED BY THE U.S. ENVIRONMENTAL PROTECTION AGENCY

Test Project	Plant	Boiler No.	Boiler Size Megawatts	Coal Characteristics Nitrogen	Coal Characteristics Moisture	Full Load NO_x Emissions Nanograms per joule ($lb/10^6$ Btu)
				Percent by Weight		
1	A	2	130	1.3	9.1	145-202 (0.34-0.47)
2	A	2	130	1.3	9.1	109-176 (0.25-0.41)
3	B	1	350	0.4	30.4	147-195 (0.34-0.46)
4	C	2	800	1.05	13.0	162-209 (0.38-0.49)
5	D	2	430	1.2	8.0	133-198 (0.31-0.46)
6	E	1	520	0.65	24.4	159-236 (0.37-0.55)

Except for the Plant C test, no significant increase in CO emissions was measured.[9,13,14] For the Plant C tests, CO emissions were 330 ppm at 3 percent oxygen in the low NO_x mode as compared with 64 ppm at 3 percent oxygen in the normal firing mode.[9] Neither of these CO concentrations are high enough to cause air pollution problems.

Boiler efficiencies were measured during three of the five test projects.[9,13,14] As shown by Table 6-8, boiler efficiency was about the same with low NO_x operations as with normal operations. Under field conditions boiler efficiency should be slightly higher in the low NO_x mode than under normal conditions because more careful combustion control is required for low NO_x control than for normal boiler operation.

Table 6-9 , 6-10, 6-11, and 6-12 show corrosion test results for plants A, C, D, and E of Table 6-7.[9,13,14] No corrosion data are reported for plant B of Table 6-7. The tests involved measuring metal loss from coupons exposed at temperatures ranging from 315°C to 400°C (600-750°F). Coupon metal loss for the Plant A tests of Table 6-9 were statistically greater during low NO_x operation than during normal operation when analyzed at the 95 percent confidence level.[13,16] However, the magnitude of the low NO_x metal losses at Plant A is not enough to indicate any serious corrosion. Although for the Plant C tests of Table 6-10, the average coupon metal loss was greater during normal operation than during low NO_x operations, there is no statistical difference betwen the normal firing and low NO_x losses at the 95 percent confidence level.[9,16] For Plant D (Table 6-11) average coupon metal loss was less during low NO_x firing than during normal firing when analyzed at the 95 percent confidence level.[14,16] For Plant E (Table 6-12), average metal loss was the same for normal and low NO_x firing. The metal losses reported in Tables 6-9, 6-10, 6-11, and 6-12 provide data on

Table 6-8

COMPARISON OF AVERAGE BOILER EFFICIENCIES[9,13,14]

BASELINE VERSUS LOW NO_x MODE

	Boiler Efficiency Percent	
	Baseline	Low NO_x
Plant A	89.1	89.0
Plant C	89.4	89.5
Plant D	89.4	89.7

TABLE 6-9

PLANT A CORROSION TEST RESULTS FOR COUPONS EXPOSED[13] 30 DAYS AT 315-400°C (600-750°F)

Probe Location	Coupon No.	Coupon Metal Loss-Micrometres per year (Mils/yr.)	
		Normal Firing	Low NO_x Firing
1	1	49.2(1.94)	68.2(2.68)
	2	53.5(2.11)	79.0(3.11)
	3	46.2(1.82)	79.6(3.13)
	4	33.9(1.33)	54.5(2.14)
	Average	45.7(1.80)	70.3(2.77)
2	1	44.5(1.75)	86.3(3.40)
	2	55.4(2.18)	52.1(2.05)
	3	43.8(1.73)	52.1(2.05)
	4	30.9(1.22)	52.1(2.05)
	Average	43.6(1.72	60.7(2.39)
3	1	45.9(1.81)	84.4(3.32)
	2	41.2(1.62)	96.3(3.79)
	3	26.2(1.03)	100.5(3.96)
	4	19.4(0.76)	94.2(3.71)
	Average	33.2(1.3.)	93.9(3.70)
4	1	21.5(0.85)	68.8(2.71)
	2	33.8(1.33)	75.9(2.99)
	3	35.5(1.40)	44.6(1.76)
	4	28.5(1.12)	44.6(1.76)
	Average	29.8(1.17)	58.5(2.30)
5	1	--	--
	2	60.2(2.37)	63.0(2.48)
	3	53.3(2.10)	60.6(2.38)
	4	44.5(1.75)	--
	Average	52.6(2.07)	61.8(2.43)
	Test Average	41.0(1.61)	69.0(2.72)

TABLE 6-10

PLANT C CORROSION TEST RESULTS FOR COUPONS EXPOSED[9] 300 HOURS AT 385°C (725°F)

Boiler No.	Probe No.	Coupon No.	Coupon Metal Loss - Micrometres per year (Mils/yr) Normal Firing	Low NO_x Firing
1	1 (North side)	1	1595 (62.8)	--
		2	813 (32.0)	--
		3	541 (21.3)	--
		Probe Average	983 (38.7)	--
1	2 (South Side)	1	384 (15.1)	--
		2	269 (10.6)	--
		3	335 (13.2)	--
		Probe Average	324 (13.0)	--
		Test Average	656 (25.8)	--
2	3 (North side)	1	--	1113 (43.8)
		2	--	742 (29.2)
		3	--	500 (19.7)
		Probe Average	--	785 (30.9)
2	4 (South Side)	1	--	411 (16.2)
		2	--	384 (15.1)
		3	--	394 (15.5)
		Probe Average	--	396 (15.6)
		Test Average	--	591 (23.3)

Table 6-11

PLANT D CORROSION TEST RESULTS FOR COUPONS EXPOSED[14] 30 DAYS AT 315-400°C (600-750°F)

		Coupon Metal Loss Micrometres per year (Mils/Yr)	
Probe Location	Coupon No.	Normal Firing	Low NO_x Firing
1	1	108 (4.28)	25.2 (0.99)
	2	102 (4.02)	30.7 (1.21)
	3	55.5 (2.30)	22.2 (0.87)
	4	24.1 (0.95)	25.8 (1.02)
	Average	73.3 (2.89)	26.0 (1.02)
2	1	71.9 (2.83)	47.1 (1.86)
	2	46.6 (1.84)	72.6 (2.86)
	3	28.1 (1.11)	53.9 (2.12)
	4	20.1 (0.79)	37.0 (1.46)
	Average	41.7 (1.64)	52.6 (2.07)
3	1	56.7 (2.23)	33.1 (1.30)
	2	58.2 (2.29)	35.8 (1.41)
	3	36.9 (1.45)	29.8 (1.17)
	4	26.7 (1.05)	27.3 (1.08)
	Average	44.6 (1.76)	31.5 (1.24)
4	1	64.8 (2.55)	46.4 (1.83)
	2	67.3 (2.65)	45.0 (1.77)
	3	49.3 (1.94)	47.6 (1.87)
	4	32.9 (1.29)	49.7 (1.96)
	Average	53.6 (2.11)	47.2 (1.86)
5	1	88.0 (3.47)	61.4 (2.42)
	2	73.4 (2.89)	49.0 (1.93)
	3	37.1 (1.46)	48.3 (1.90)
	4	13.3 (0.52)	31.6 (1.25)
	Average	53.0 (2.09)	47.6 (1.87)
	Test Average	53.3 (2.10)	41.0 (1.61)

TABLE 6-12

PLANT E CORROSION TEST RESULTS FOR COUPONS EXPOSED[14]

30 DAYS AT 315-400°C (600-750°F)

Probe Location	Coupon No.	Coupon Metal Loss Micrometres per year (Mils/Yr) Normal Firing	Low NO_x Firing
1	11	239 (9.41)	109 (4.29)
	12	227 (8.94)	96.3 (3.79)
	13	125 (4.92)	100 (3.94)
	14	107 (4.21)	220 (8.66)
	Average	175 (6.89)	131 (5.16)
2	11	168 (6.61)	143 (5.63)
	12	166 (6.54)	168 (6.61)
	13	90.2 (3.55)	166 (6.54)
	14	72.8 (2.87)	141 (5.55)
	Average	124 (4.88)	155 (6.10)
3	11	130 (5.12)	190 (7.48)
	12	139 (5.47)	152 (5.98)
	13	105 (4.13)	112 (4.41)
	14	106 (4.17)	122 (4.80)
	Average	120 (4.72)	144 (5.67)
4	11	92.6 (3.65)	120 (4.72)
	12	105 (4.13)	128 (5.04)
	13	81.1 (3.19)	124 (4.88)
	14	66.7 (2.63)	79.2 (3.12)
	Average	86.4 (3.40)	113 (4.45)
5	11	124 (4.88)	94.7 (3.73)
	12	147 (5.79)	106 (4.17)
	13	121 (4.76)	77.3 (3.04)
	14	97.1 (3.82)	69.4 (2.73)
	Average	122 (4.80)	86.7 (3.41)
	Test Average	126 (4.96)	126 (4.96)

comparative metal loss, but are not quantitative values of boiler tube wastage (corrosion) rates.[9,13,14] After analyzing the foregoing data and other internal data, Combustion Engineering says that increased waterwall corrosion rates would not be a problem with low NO_x operation of their modern pulverized coal-fired steam generators and CE is willing to guarantee a NO_x limit of 260 nanograms per joule (0.6 $lb/10^6$ Btu) for new pulverized coal-fired steam generators which burn Eastern coal and 210 nanograms per joule (0.5 $lb/10^6$ Btu) for units which burn lower rank Western coals.[4,15]

Analysis of the effect of low NO_x operation on steam superheat and reheat temperatures during the Plant A tests shows that low NO_x emission levels can be achieved without steam superheat or reheat temperature reduction when the steam generator is operated in the range one-half to full load.[13,14,16] No slagging problems were encountered during any of the tests which could not be controlled with the normal sootblowing systems.[9,13,14]

A flame ionization analyzer was used during the Plant A, Plant D, and E tests to measure hydrocarbon emissions.[13,14] Hydrocarbon emission levels during these tests were below the lower limit of detection.[13,14]

As previously discussed and shown in Tables 6-7, 6-8, 6-9, 6-10, 6-11, and 6-12, NO_x emissions from Combustion Engineering modern design pulverized coal-fired steam generators can be controlled to low levels without adverse side effects. During five test projects, the low NO_x emitting steam generators were purposely operated under conditions which would produce higher NO_x emission levels.[9,13,14] These conditions involved operating with higher combustion gas oxygen content, no overfire air, and/or improper burner and overfire air nozzle tilts. Table 6-13 shows that much higher NO_x levels were measured when firing conditions

TABLE 6-13

Summary of Maximum Full Load NO_x Emission Measurements During U. S. Environmental Protection Agency Tests of Modern Combustion Engineering Tangential Coal-Fired Steam Generators[9,13,14]

Test Project	Source	Combustion Air Settings Percent Open		Nozzle Tilt Milliradians (degrees) from Horizontal		Total Oxygen Content Percent	NO_x Emissions Nanograms per joule ($lb/10^6$ Btu)
		Secondary Air	Overfire Air	Burner Nozzle	Overfire Air Nozzle		
A	A	100	0	-384 (-22)	0	4.3	239 (0.56)
B	A	100	0	- 35 (- 2)	0	7.3	271 (0.63)
-	C	100	10	+436 (+25)	0	4.8	295 (0.69)
-	B	40	0	-454 (-26)	0	4.0	269 (0.63)
-	D	100	0	NR	NR	6.8	365 (0.85)

NR = No Record

deviated from the conditions required for low NO_x control.[9,13,14] Consequently, it is very important that NO_x emissions be monitored continuously and accurately if real emission reduction is to be effected by new source performance standards for NO_x emissions from combustion.

6.2.3 Foster Wheeler Energy Corporation and Riley Stoker Corporation

Foster Wheeler reports their modern units are equipped for overfire, interstage, and curtain air, (boundary air) and are designed to limit NO_x emissions by reducing combustion air to the firing zone.[3] Curtain air is used to prevent reduced air conditions at the boiler walls which would cause accelerated tube wastage (corrosion) or slagging.[3] A Foster Wheeler coal-fired steam generator was started up in December 1976 at a Western power plant firing 22.6 megajoules per kilogram (9700 Btu/lb), 0.9 percent sulfur coal.[11,12] This steam generator is subject to a State of New Mexico regulation limiting NO_x emissions to no more than 193 nanograms per joule (0.45 $lb/10^6$ Btu). The steam generator is still in the shakedown phase of NO_x emission control.[11] Foster Wheeler Corporation is developing a low-turbulence dual throat coal burner with a double annulus throat configuration for secondary air injection and individual control of each annulus air supply.[17] The primary mechanisms by which the new burner limits NO_x emissions are control of turbulence and delayed mixing of fuel and air, thereby minimizing fuel NO_x conversion.[17]

The special Foster Wheeler burner has been tested on three units; two 265 MW opposed-fired units and one 75 MW front wall-fired unit. All of these units were modified existing units. Modifications included provision for overfire and boundary air. NO_x emissions were reduced about 48 percent by the special burner and were reduced about 67 percent when full overfire air was used in conjunction with the dual throat burner.[18] NO_x was reduced to about 300-350 ppm by the special burner with the overfire air 20 percent open.[18] CO concentrations were below 50 ppm and unburned fly ash carbon was less than one percent. When the overfire air was opened 100 percent and the burners were adjusted for minimum NO_x, fly ash carbon increased to about 2.5 percent and slag began to accumulate after about 24 hours of full-load operation.[18] Slagging was substantially alleviated, although not eliminated by the combined effect of the special burner and by the use of boundary air.[18] The furnaces were conservatively sized because of the slagging characteristics of the coal.[18] No tube wastage was evident from firing the good quality 26.77 megajoules per kilogram (11,500 Btu/lb), 0.6 percent sulfur coal.[18]

Riley Stoker modern design units are equipped for underfire, overfire, and sidefire air, and emissions of NO_x are limited by reducing combustion air in the firing zone.[2] These units are designed for about 280 megajoules per second per square metre (1.5×10^6 Btu/hr/ft^2) heat release rates as compared with heat release rates for older pulverized coal-fired units of 430 megajoules per second per square metre (2.25×10^6 Btu/hr/ft^2).[2]

Riley Stoker Corporation is currently modifying the burners used in its furnace design to reduce NO_x emissions.[17] The new burners are designed to control mixing of fuel and air to reduce thermal and fuel NO_x.[17] With the new burners and changes in furnace design, Riley Stoker expects to achieve low NO_x emissions with its new boilers without increased carbon or unburned hydrocarbon loss.

6.2.4 Summary of NO_x Control Status

U. S. Environmental Protection Agency test results show that NO_x emissions from modern Combustion Engineering pulverized coal-fired steam generators can be limited to levels less than 260 nanograms per joule (0.6 lb/10^6 Btu) without any significant adverse side effects. Combustion Engineering will guarantee its new units to meet this limit for any type of coal.[4,15] For plants firing coal which has little tendency to cause slagging or tube wastage, any of the four manufacturers is capable of furnishing coal-fired steam generators which will limit NO_x emissions to a level less than 210 nanograms per joule (0.5 lb/10^6 Btu).[4,15]

There is not enough data or experience to indicate whether Babcock and Wilcox, Foster Wheeler, or Riley Stoker modern pulverized coal-fired steam generators are capable of achieving low NO_x emission levels without adverse side effects when slagging or corrosive coals are fired.

6.3 FEASIBILITY OF CONTINUOUS NO_x CONTROL

Table 6-14 shows data on NO_x emissions from tangentially fired boilers firing Western subbituminous coal.[19] This Western power plant is required to control emissions to a level less than 300 nanograms per joule (0.7 lb/10^6 Btu). As shown by Table 6-14, emissions were substantially below the foregoing level. The plant is equipped to reduce or to increase NO_x emissions from the two tangentially fired steam generators by controlling the proportional quantities of overfire and secondary air. The plant reports that it is seldom necessary to change overfire air damper settings since, as shown, NO_x emission levels are characteristically low.[19] With constant overfire air damper settings, and by modulating secondary air control, NO_x emission levels are the highest at full load. NO_x emissions decrease as the load is reduced. Any necessary changes in overfire air damper settings are made by plant engineers or management personnel and are not made by shift operators. The data show that NO_x emissions from subbituminous coal-fired steam generators are continuously and consistently controlled to a level less than 210 nanograms per joule (0.5 lb/10^6 Btu).

TABLE 6-14

NOVEMBER 1977 NO_x EMISSION CHARACTERISTICS OF TWO 350 MW[19] TANGENTIALLY FIRED COAL FIRED STEAM GENERATORS

Nanograms per joule ($lb/10^6$ Btu)

	Unit 1		Unit 2	
Day	24 Hour Average	Peak	24 Hour Average	Peak
11-1	170 (.40)	205 (.48)	a	a
2	175 (.41)	230 (.53)	a	a
3	190 (.44)	230 (.53)	a	a
4	210 (.49)	290 (.67)	140 (.33)	150 (.35)
5	105 (.25)	195 (.45)	190 (.44)	220 (.51)
6	205 (.48)	295 (.69)	180 (.42)	200 (.47)
7	215 (.50)	235 (.55)	155 (.36)	170 (.39)
8	205 (.48)	240 (.56)	175 (.41)	200 (.46)
9	230 (.53)	245 (.57)	180 (.42)	235 (.55)
10	215 (.50)	270 (.63)	130 (.30)	185 (.43)
11	210 (.49)	240 (.56)	125 (.29)	190 (.44)
12	190 (.44)	220 (.51)	125 (.29)	140 (.32)
13	185 (.43)	200 (.47)	160 (.37)	215 (.50)
14	180 (.42)	200 (.46)	170 (.40)	200 (.47)
15	190 (.44)	215 (.50)	a	a
16	195 (.45)	220 (.51)	a	a
17	210 (.49)	235 (.55)	a	a
18	260 (.60)	290 (.67)	56 (.13)	120 (.28)
19	150 (.35)	170 (.39)	125 (.29)	195 (.45)
20	170 (.39)	190 (.44)	95 (.22)	130 (.30)
21	180 (.42)	205 (.48)	155 (.36)	170 (.39)
22	140 (.33)	170 (.40)	180 (.42)	200 (.47)
23	135 (.31)	140 (.33)	205 (.48)	225 (.52)
24	140 (.32)	150 (.35)	215 (.50)	230 (.53)
25	115 (.27)	150 (.35)	110 (.26)	180 (.42)
26	140 (.32)	155 (.36)	145 (.34)	210 (.49)
27	115 (.27)	120 (.28)	200 (.47)	205 (.48)
28	130 (.30)	155 (.36)	175 (.41)	200 (.46)
29	135 (.31)	160 (.37)	170 (.40)	230 (.53)
30	140 (.32)	165 (.38)	130 (.30)	175 (.41)

[a] No data - Unit out of service

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7. ENVIRONMENTAL IMPACT

7.1 GENERAL

As discussed in Chapter 6, NO_x emissions from large pulverized coal-fired steam generators can be controlled without loss of boiler efficiency or an increase in carbon monoxide or particulate emissions. Hydrocarbon emissions from low NO_x emitting sources are below the limit of detection of a flame ionization analyzer.[1] Although it is logical to conclude that if carbon monoxide emissions are not increased, polycyclic organic matter emissions are not increased, there is not enough data to prove this theory.

More effective control of NO_x emissions from large pulverized coal-fired steam generators using the design and operating techniques discussed in Chapter 6 does not adversely affect solid waste, water pollution, noise, or energy environmental impact.

7.2 AIR POLLUTION IMPACT

7.2.1 Effect on Ambient Air Quality

Table 7-1 shows emission source characteristics for various sized model sources emitting NO_x at full load capacity at the level of the current NO_x new source performance standard for pulverized coal-fired steam generator of 300 nanograms per joule (0.7 lb/10^6 Btu).[2,3] As shown, air quality was measured for three different stack heights.

TABLE 7-1

EMISSION SOURCE CHARACTERISTICS OF THE PROTOTYPE PULVERIZED COAL COMBUSTION PLANTS[2,3]

Production Rates	Case No.	No. of Stacks	Emission Rates (gm/sec)		Stack Height (metres)	Stack Temp. (°K)	Stack Velocity (m/sec)	Stack Diam. (metres)	Control Building Height (metres)
			NO	NO_2					
25 MW	1	1	14.2	0.2	75	400	20	1.68	15
	2	1	14.2	0.2	175	400	20	1.68	15
	3	1	14.2	0.2	275	400	20	1.68	15
300 MW	4	1	171	2.6	75	400	20	5.82	30
	5	1	171	2.6	175	400	20	5.82	30
	6	1	171	2.6	275	400	20	5.82	30
1,000 MW	7	1	569	8.8	75	400	20	10.62	60
	8	1	569	8.8	175	400	20	10.62	60
	9	1	569	8.8	275	400	20	10.62	60

Modeling techniques are described in Appendix F.[3]

Table 7-2 shows the impact of 25, 300, and 1000 megawatt sources on air quality.[3] The models assume that plants would be located in flat or gently rolling terrain with a meteorological regime which is unfavorable to the dispersion of pollutants.[3] Downwash and retardation effects were evaluated for the control building heights given in Table 7-1.[3] The models assume that the plants are operated at full load during an entire year. The values reported are the maximum ground level concentrations that were calculated for downwash, retardation, or characteristic dispersion, whichever was the greatest. Further information on modeling techniques is given in Appendix F. As shown by Table 7-2, impact on air quality increases with plant size and decreasing stack height. In actual practice, the average annual concentrations would be somewhat less, because plant load factors are usually less than 100 percent.

As shown by Table 7-1, nitrogen oxides emissions were estimated for NO and NO_2. Nearly all of the nitrogen oxides emissions from combustion are emitted as NO.[4] Assuming oxidation of the NO of Table 7-2 to NO_2 and excluding Case No. 7 which reflects the effect of severe downwash yields a range of annual NO_x concentrations (as NO_2) of from less than 0.3 to less than 2 micrograms per cubic metre, compared to the Primary and Secondary National Ambient Air Quality Standard for nitrogen dioxide of 100 micrograms per cubic metre.[5]

The maximum ground level concentrations of Table 7-2 are for sources emitting at the level of the current NO_x new source performance

TABLE 7-2

MAXIMUM POLLUTANT CONCENTRATIONS[a] (μg/m^3)[3]

Averaging Period	Case	NO[c]	NO_2	Distance (km)
Annual	1	0.7	<0.1	0.9
	2	0.2	<0.1	3.0
	3	<0.1	<0.1	2.3
	4	1.6	<0.1	6.4
	5	0.5	<0.1	14.8
	6	0.2	<0.1	20.01
	7	930	14	0.3[b]
	8	0.7	<0.1	20.5
	9	0.4	<0.1	23.3

[a] Concentrations have been pro-rated according to specific emission rates.

[b] First ring, downwash.

[c] NO oxidizes in atmosphere to NO_2. However, it is not known what percentage of NO would be oxidized for the 9 cases.

standard of 300 nanograms per joule (0.7 lb/10^6 Btu).[2] Reducing NO_x emissions to lower levels would proportionally reduce the NO_x concentrations shown in Table 7-2.

7.2.2 Effect on Air Emissions

Reducing NO_x emissions from pulverized coal-fired steam generators from the level of the current new source performance standard of 300 nanograms per joule (0.7 lb/10^6 Btu) to a level of 260 ng/J (0.6 lb/10^6 Btu) would be equivalent to about a 14 percent reduction in emissions. A 29 percent reduction in emissions would result from the restriction of emissions to a level of 210 nanograms per joule (0.5 lb/10^6 Btu).

Because it takes about 5 years to construct a pulverized coal-fired power generation system, the air emission impact of a lower NO_x limit would not begin for at least five years after the lower limit became effective. Thus, the earliest impact would begin about 1982 or 1983. According to power industry estimates compiled by the Federal Power Commission, the total capacity of fuel burning power generation facilities will increase by about 189,400 megawatts during the 10 year period from the end of 1983 to the end of 1993.[6,7] It is estimated about 161,000 megawatts (or 85 percent) of this new capacity will be pulverized coal-fired other than lignite capacity.[7] Based on the foregoing estimate about 2.910 teragrams (3,210,000 short tons) of additional NO_x would be emitted in the 1993 year from new pulverized coal (other than lignite) fired units which are added during the period 1983 through 1993, assuming that emissions are limited to the level of the current new source performance standard of 300 nanograms per joule (0.7 lb/10^6 Btu). For control levels below the current standard, nationwide NO_x emission rates would also be increased by power industry expansion of coal-fired steam generating capacity. However, the increase would not be as great as with the current 300 nanogram per joule limit. This is demonstrated in Table 7-3. Beyond 1993 NO_x control levels below the current standard would continue to temper the impact of new pulverized coal-fired steam generator activations on annual nationwide NO_x emissions.

7.3 SOLID WASTE, WATER POLLUTION, NOISE, AND ENERGY IMPACT

As discussed in Chapter 6, the viable techniques for reducing NO_x emissions from pulverized coal-fired steam generators involve changing the way the fuel and air are introduced into the combustion chamber. Since no additional waste materials are generated, more effective NO_x control does not increase or decrease the quantity of wastes and does not change the character of the wastes. The more effective NO_x control techniques discussed in Chapter 6 do not change the character or magnitude of water or noise pollution.

Although the test results discussed in Chapter 6 fail to show any statistically significant difference in boiler efficiency for normal firing as compared with low NO_x firing, it is likely fuel consumption will be slightly less when NO_x emissions are controlled to a lower limit. Thus, more effective NO_x control will probably have a slight beneficial impact on energy consumption.

As discussed in Chapter 6, NO_x emissions can be controlled to lower levels without increasing energy losses which would be indicated

Table 7-3

THE EFFECT OF VARIOUS NO_x CONTROL LEVELS ON EMISSIONS FROM 161,000 MEGAWATTS OF COAL-FIRED ELECTRIC UTILITY STEAM GENERATING CAPACITY BUILT 1983-1993 [a,b]

NO_x Control Level Nanograms per joule (lb/million Btu)	% Reduction Below Current Standard	Total NO_x Teragrams (tons per year)	Difference Teragrams (tons per year)
300 (0.7)	0	2.91 (3.21×10^6)	0 (0)
260 (0.6)	14%	2.49 (2.75×10^6)	0.42 (4.6×10^5)
210 (0.5)	29%	2.08 (2.29×10^6)	0.83 (9.2×10^5)

[a] It is expected that 1983 will be the first year that new units will be subject to the revised NO_x standards (40 CFR, Part 60, Subpart D(a).

[b] The current standard for NO_x emissions from new units is 300 ng/J (0.7 lb/million Btu) (40 CFR, Part 60, Subpart D).

by increased ash combustible content or increased CO emissions. Although the quantity of total excess air used during low NO_x firing is much the same as that used during normal firing, it is likely that for long term boiler operation the total excess air used will be less for low NO_x firing than for normal firing. This is because operators will need to control combustion air rates within narrower limits when firing in the low NO_x mode than when firing in the normal mode. Lower excess air increases boiler efficiency.

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CHAPTER 8. ECONOMIC IMPACT ANALYSIS

8.1 INDUSTRY PROFILE

8.1.1 General Industry Background

The market for large coal-fired boilers is dominated by the electric utility industry. As shown in the table below, over 88 percent of all coal-fired units and over 98 percent of the rated megawatts installed since 1960 have been electric utility power generation applications.

Table 8-1. COAL-FIRED UNITS INSTALLED, 1960-1976[1]

	Electric Utilities	%	Industry	%	Total	%
# of units installed	404	88.8%	51	11.2%	455	100%
Installed megawatt capacity	159,051	98.4%	2,519	1.6%	161,540	100%

The electric utility industry itself has undergone some significant market perturbations in recent years. As Figure 8.1 shows, both energy and peak load demand maintained a relatively stable growth rate of between five and nine percent per year from 1961 through the early 1970's. In 1973 a worldwide recession coupled with the Arab oil embargo caused a drop in annual peak power demand for electricity in 1973. Energy demand showed virtually no growth in 1974, and only began to climb as the recession

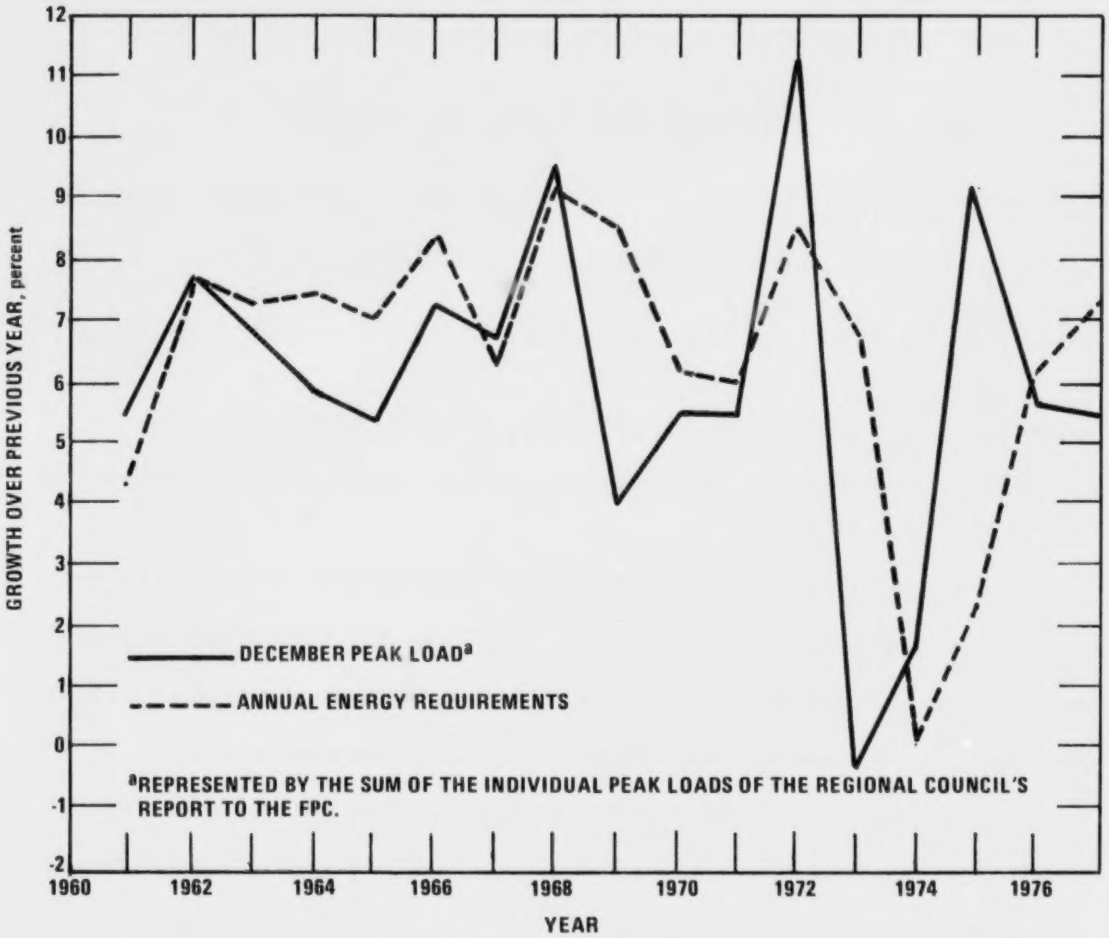


Figure 8-1[2]. Percentage growth rate over previous year reported by major U.S. utility systems[a].

bottomed out in 1973. Peak power demand for electricity rose at a rate of two to seven percent in 1975 and 1976, an increase over 1973 and 1974 but still somewhat lower than the 1960 to 1972 period.

With the long lead times in plant construction cycles in this industry, the capital programs tend to build a great deal of momentum. It is not possible to respond immediately to changes in the demand for electric power. Figure 8-2 shows how reserves in the power industry soared in 1973 and 1974 to a high of over 50 percent excess capacity over winter peak demand. The summer peak margins would be somewhat lower. Not only have the utilities suffered from this overbuilt circumstance, but a coincidental problem involves the precipitous drop in collective system capacity factor for the industry. Figure 8-3 shows this distinctive drop in capacity factors from 1973 to 1974. The result of these phenomena are utilities with over-commited capital programs supported by systems generating less revenues due to the lower plant utilization.

This problem has lessened more recently due to increased demand for electric power, but peak winter reserve capacity is 46 percent and will continue to be above 40 percent through the end of the decade. As a result, orders were very slack for boilers since 1974. In 1974, 69 coal-fired boilers with a rated capacity of 32,964 MWe were ordered; this number shrank to 22 (10,774 MWe) in 1975 and 13 (6,312 MWe) in 1976. This downward trend appears to have reversed itself in 1977. Orders for the current year are expected to total at least 20, with capacity of approximately 13,000 MWe.[3] Market analysts are confident of an increasingly strong market as utilities convert to coal or prepare to construct new units that have been delayed due to sluggish demand for electric power. However, it will be at least several years before the dislocations that occured in 1973 and 1974

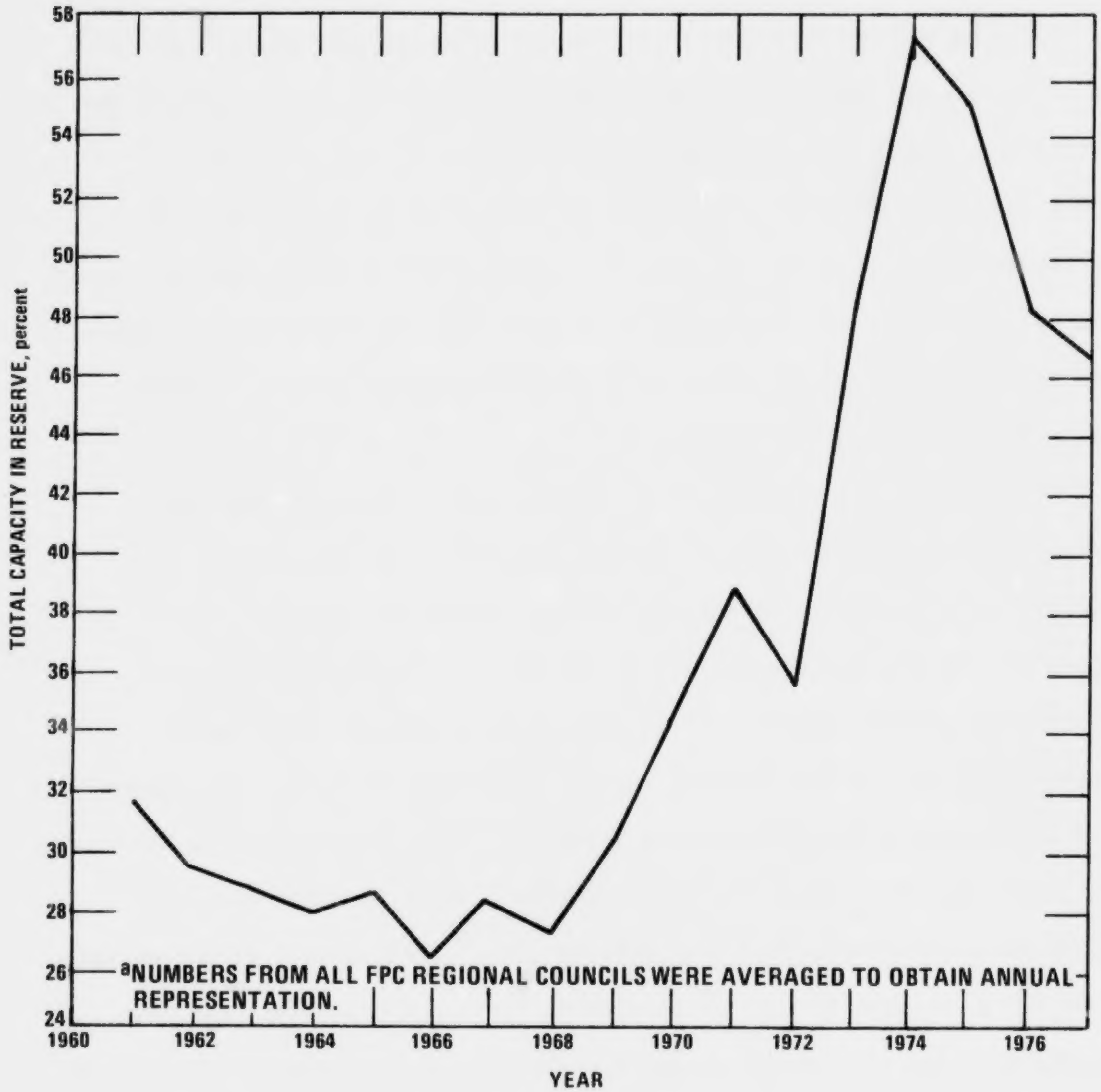


Figure 8-2[4]. Annual peak reserves as a percentage of total available capacity, 1961-1977[a].

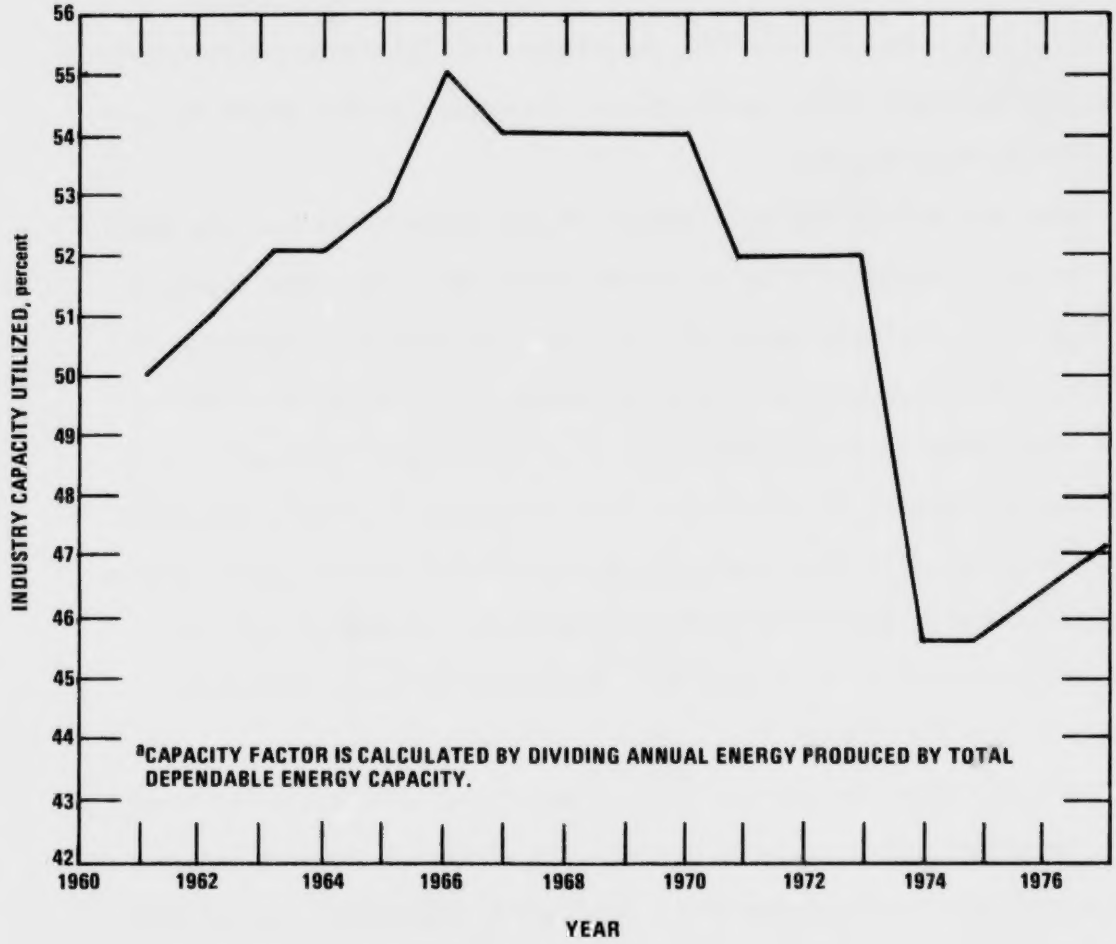


Figure 8-3[5]. Annual capacity factor for the major U.S. electric utilities[a].

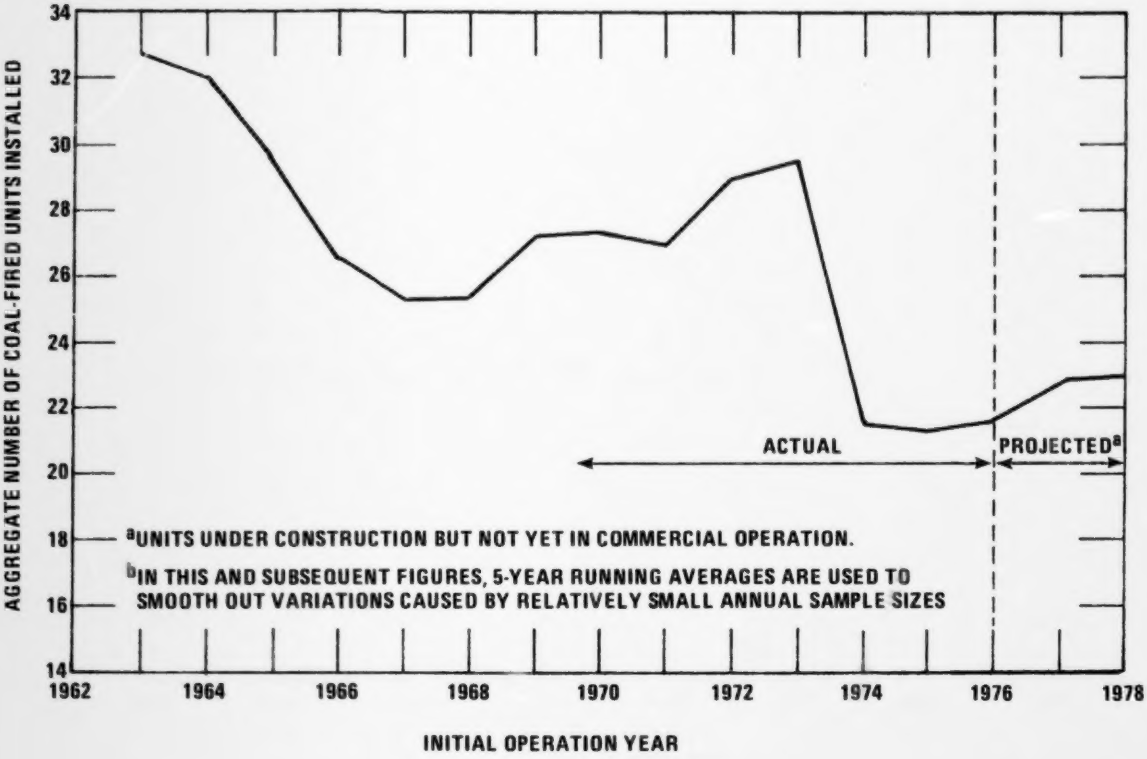
are eliminated. A return to a pre-recession level of power boiler sales probably cannot be expected for several years. Contributing to this circumstance is the large backlog of boilers already ordered but delayed due to utility uncertainty over economic and regulatory conditions in the near future and passage of a comprehensive national energy plan.

8.1.2 Coal As The Basic Fossil Fuel For Electric Generation

The economic and political problems that have surrounded oil and natural gas supplies over the past few years have brought on a strong interest in coal as the basic fuel for electric generation. As was indicated in Chapter 3, the major fossil fuel boiler manufacturers anticipate no new orders for oil- and gas-fired power boilers.

Figure 8-4 depicts the total number of coal-fired units (over 25 MWe) installed (or scheduled for installation) since 1960. The steep change in 1973 is indicative of the number of units being delayed or cancelled by the utilities. There may be some additional delays among the units scheduled out to 1978; however, the recovery from 1973 is apparent. Generally, coal demand can be expected to grow faster than the growth of primary electric demand since coal will most likely replace a sizeable portion of the generation that otherwise would have been supplied by oil or natural gas. As discussed in Chapter 3, it is uncertain how much of this new generation capacity will be from fossil fuels and how much will be nuclear.

Figure 8-5 shows the average size of coal-fired units installed since 1963. The slight downtrend in number of units installed shown in Figure 8-4 is more than offset through the early 1970's with consistently larger unit sizes. The average size of a coal-fired unit stabilized in the early 1970's. To a limited extent this probably is attributable to technological limitations in the size of the generation units, but more importantly the economic



[a]UNITS UNDER CONSTRUCTION BUT NOT YET IN COMMERCIAL OPERATION.

[b]IN THIS AND SUBSEQUENT FIGURES, 5-YEAR RUNNING AVERAGES ARE USED TO SMOOTH OUT VARIATIONS CAUSED BY RELATIVELY SMALL ANNUAL SAMPLE SIZES

Figure 8-4[6]. Aggregate annual number of installed coal-fired units over 25MW on a 5-year running average[b].

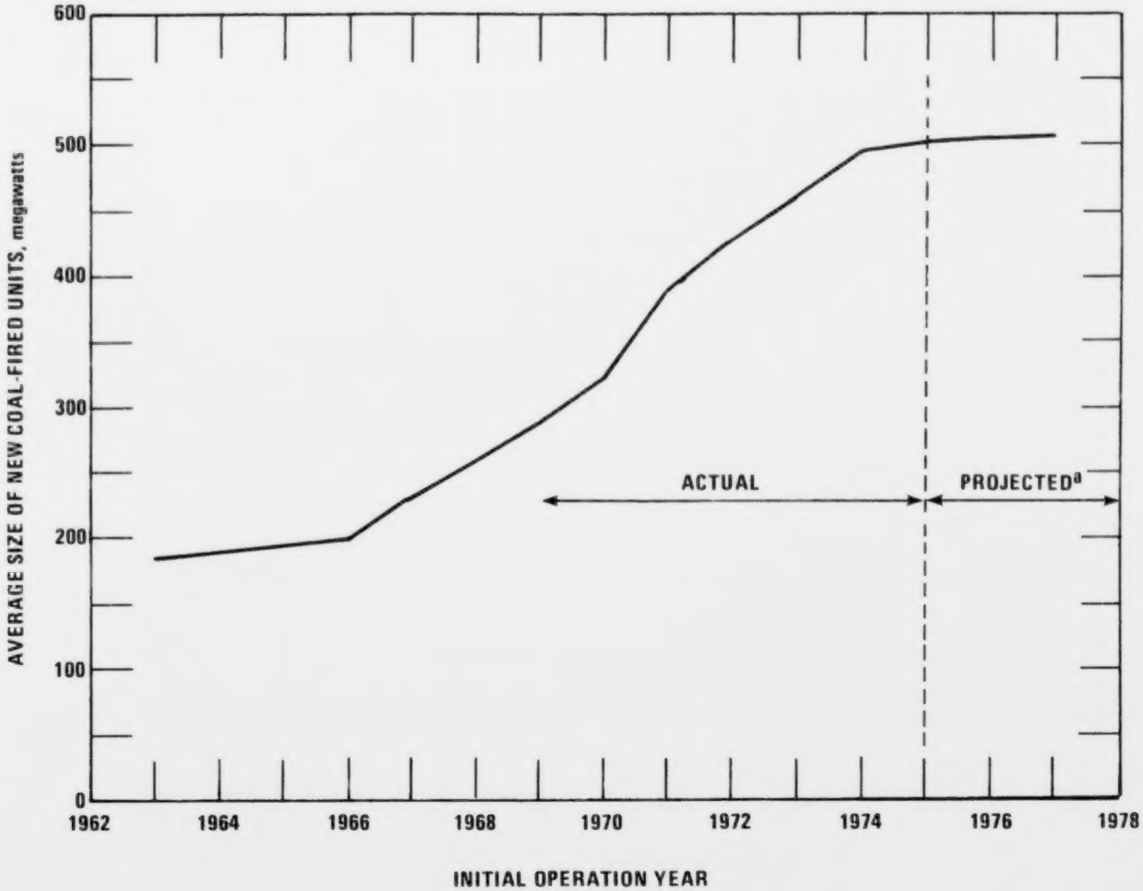


Figure 8-5. Average size of newly installed coal-fired units on a 5-year running average. 7

implications of relying on one unit for too large a percentage of a utility's total generation need had started to limit the size of newly installed units. However, unit size is beginning to escalate, and a new generation of boilers installed in the mid- and late 1980's will be somewhat larger than the generation of boilers constructed in the 1970's. The new boilers will average about 554 MWe.

8.1.3 Competitors In The Coal-Fired Boiler Industry

There are four competitors in the large (greater than 25 MWe) coal-fired boiler market: Combustion Engineering, Inc., Foster Wheeler Corporation, Babcock and Wilcox Company, and the Riley Company. Table 8-2 shows comparative financial data for the four companies. The data are aggregated and, therefore, reflect all of the products each company produces, which vary significantly. Combustion Engineering, Inc., and Babcock and Wilcox Company both participate as primary contractors in the nuclear power generation business; all four companies supply a wide variety of products and materials closely related to the power generation industry.

Table 8-2 reflects the relative amounts of debt in the capital structure of each company as well as the relative return on sales. These may offer some insights on each company's ability to adjust to increased production or design costs caused by environmental regulations.

Table 8-2. FINANCIAL DATA FOR FOSSIL-FIRED BOILER INDUSTRY[8]

(million $, 1976)

	Combustion Engineering	Babcock & Wilcox	Foster Wheeler	Riley Company
Assets	1274.6	1129.1	476.1	151.0
Equity	398.4	415.6	128.5	33.1
Long-Term Debt	108.8	92.9	45.3	14.1
Revenues	1830.9	1691.8	1061.7	210.2
Net Income	54.2	53.1	20.5	4.9
R&D	28.8	27.4	17.3	2.5

Table 8-3 shows that there is no significant disparity between the four manufacturers' reliance on the coal-fired boiler market.

Table 8-3. RELIANCE ON COAL-FIRED BOILER MARKET FOR EACH SUPPLIER[9]

(million $, 1976)

	Revenues From Coal-Fired Boilers[a]			
	Combustion Engineering	Babcock & Wilcox	Foster Wheeler	Riley Company
Million of Dollars	245.0	230.6	197.7	42.9
Percent of Total Revenue	13%	14%	19%	20%

[a] Assumes that the equipment price for coal-fired units is $43/kW as quoted by FPC sources. Installation costs are not included since boiler vendors generally do not do site installation work.

Figure 8-6 shows the percentage market share of the coal-fired boiler market for each of these suppliers. Figure 8-7 shows the market share in total annual megawatts installed.

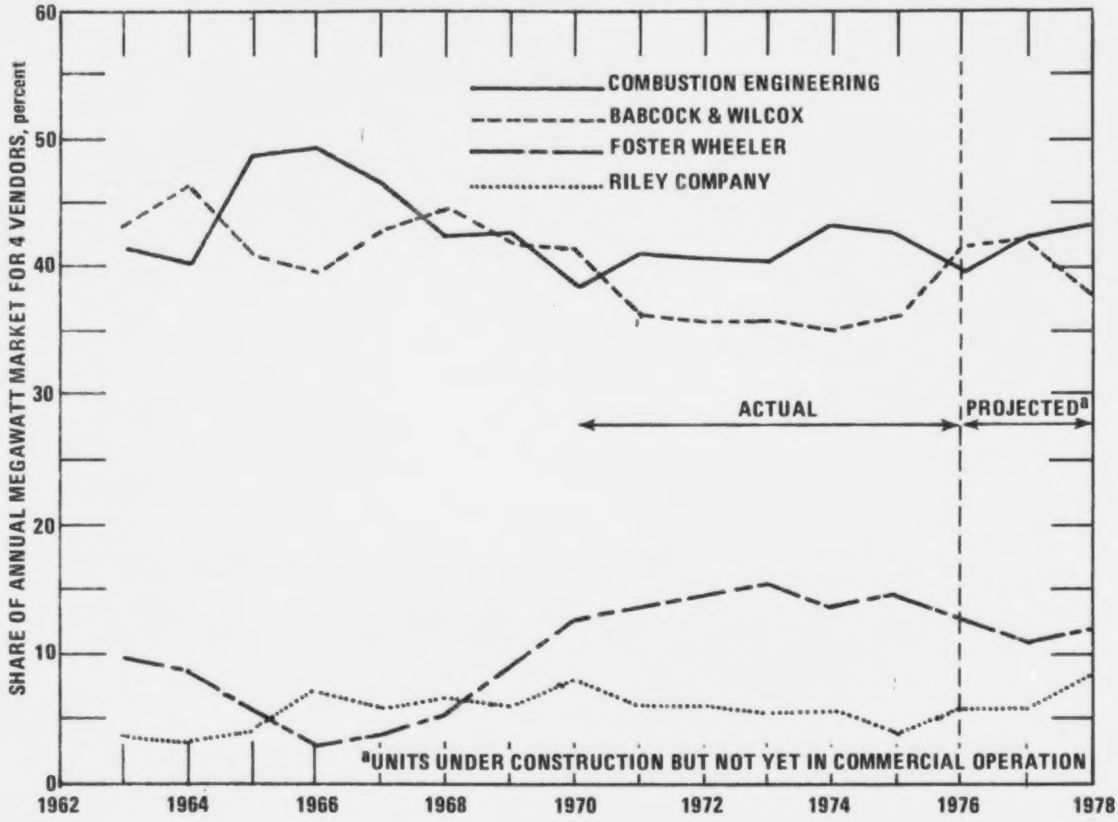


Figure 8-6[10]. Annual installed megawatt capacity as a percentage of the total coal-fired market on a 5-year running average.

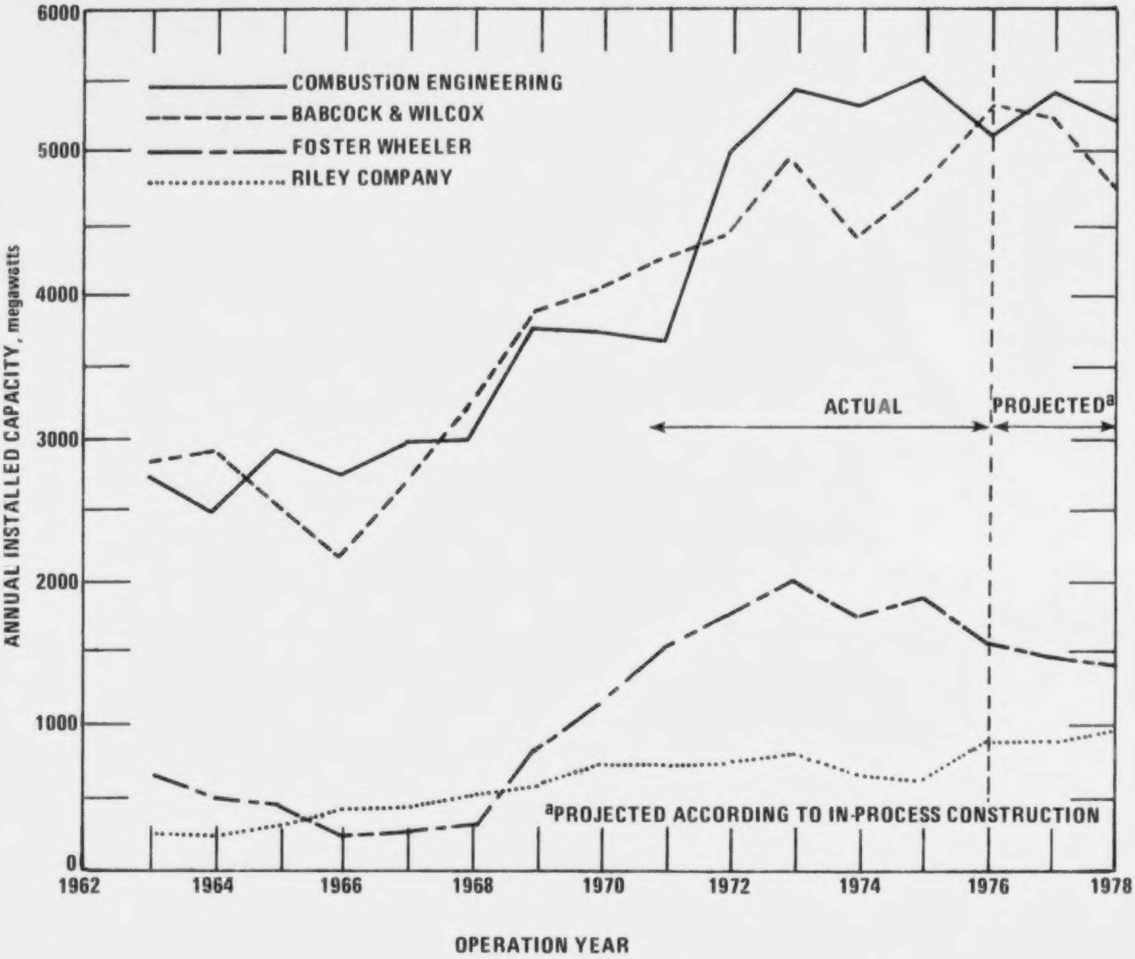


Figure 8-7[11]. Annual installed megawatt capacity for coal-fired units on a 5-year running average.

By megawatt capacity installed, Combustion Engineering and Babcock and Wilcox are the clear market leaders, with approximately 40 percent of the total market each. Foster Wheeler and the Riley Company share the remaining 20 percent of the market. Figure 8-8 shows the distribution of unit sizes by supplier for all large coal-fired units installed since 1960. The Riley Company has clearly positioned itself in the small-size unit segment of the market with one-third of its units in the 100-200 MWe class and no units over 500 MWe. The other three manufacturers have relatively similar curves with Foster Wheeler, slightly skewing toward 600-900 MWe units.

There is no indication of further market segmentation either by fuel type or geographic location of the plant. In some cases a particular supplier may have an inordinate number of units in a particular area or on a particular utility system. Ths is explained generally by the economies of plant duplication (design, maintenance, and operation factors) as well as the possibility of more effective marketing efforts by one supplier in a particular area. The market is generally mature enough so that thorough economic and technological evaluation of a bid may not indicate a clear best choice, in which case somewhat "softer" measures such as duplication of plant controls for easier operator training or more effective sales coverage may determine the winning bid.

Historically the large coal-fired boiler industry appears to be a relatively stable and mature industry with perhaps two primary segments by unit size. Among the large unit suppliers, Combustion Engineering and Babcock & Wilcox hold similar market shares in both segments. Foster Wheeler appears quite capable of surviving in the large unit segment though securing a noticeably smaller number of units. The Riley Company, on the other hand, competes primarily for smaller units and has shown some recent gains in market share for

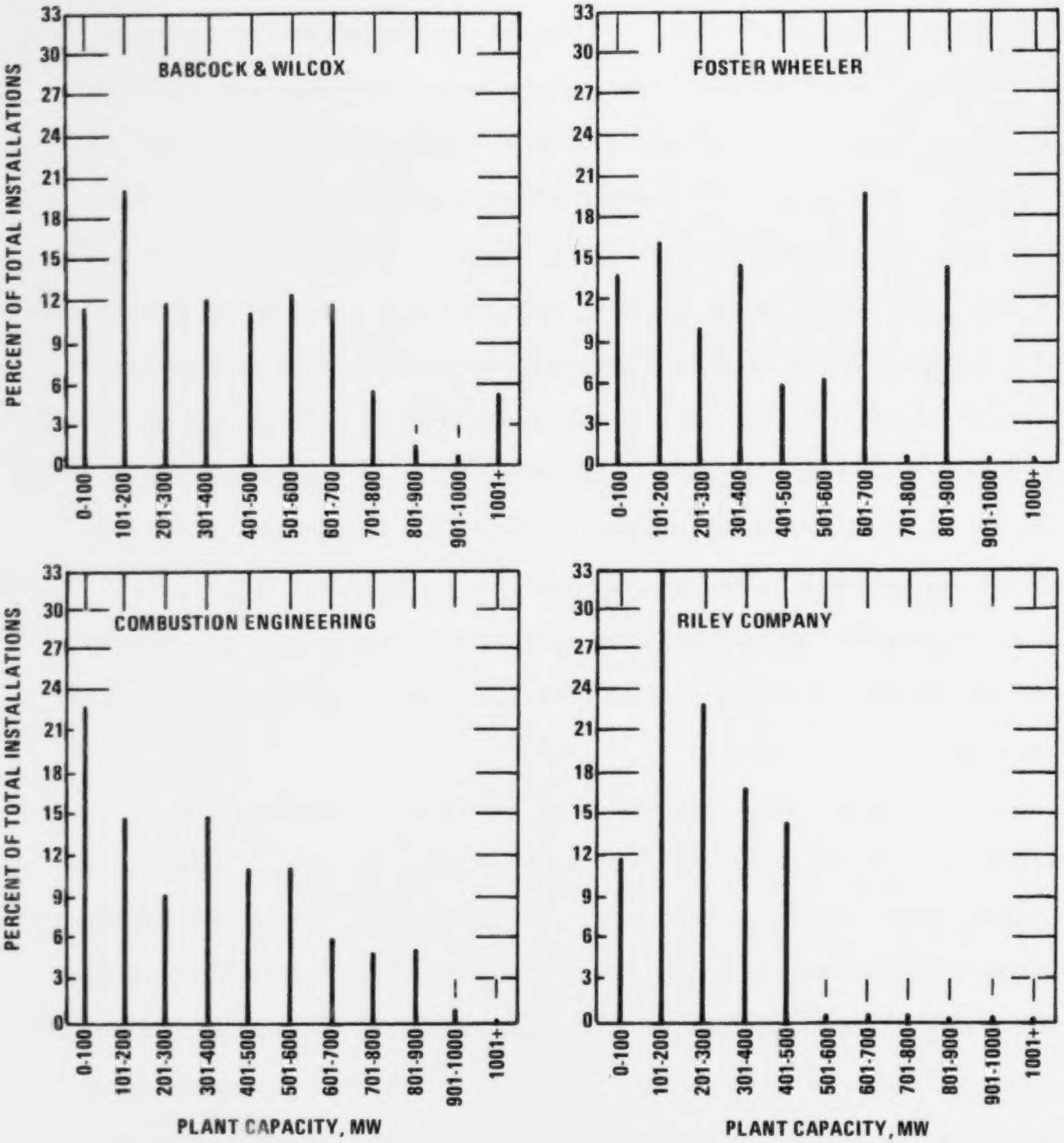


Figure 8-8[12]. Size distribution of coal-fired power plants installed 1960-1978 for 4 suppliers.

this size unit. Even though the size of the total coal-fired boiler market may be cyclical, there is no apparent reason to assume that there is going to be a significant change in the relative market shares among these four equipment suppliers in the foreseeable future.

8.2 COST OF CONTROL

The degree to which the four major boiler manufacturers (Combustion Engineering, Babcock and Wilcox, Foster Wheeler and the Riley Company can reduce NO_x emissions below the current standard of performance (300 nanograms/joule) is a function of their current boiler design, status of improved combustors, and the type of coal burned. In order to account for these factors, three scenarios have been proposed to provide a range for possible impacts.

The first scenario (Scenario I) under consideration is to postulate that all of the major boiler manufacturers will be able to comply with the proposed emission limits with their current modern design units or with insignificant modifications to current designs. This scenario would imply that none of the four manufacturer's boilers would undergo any change in capital or operating costs. This scenario is considered to be the most likely since all manufacturers have indicated some optimism in reaching levels below the current NSPS, although three manufacturers except Combustion Engineering have expressed concern about the long-term effects on the boiler of operating at such a low NO_x level. By definition this scenario has no economic impact.

The second scenario assumes that two of the manufacturers who have demonstrated the lowest NO_x emission levels (Combustion Engineering and Babcock Wilcox) can meet the proposed emission limits on all coal types and that the other manufacturers (Foster Wheeler and the Riley Company) need to modify current designs when burning corrosive coal. The assumption in this scenario is that the modifications to the current burners are relatively minor and can be accomplished without loss of market. However, Foster Wheeler and the Riley Company would have to invest in research and development to improve their burner designs. The exact amount of this investment is unclear but an upper bound approximation can be made. Babcock and Wilcox estimated in 1976 that the developmental costs for their burner system was about two million dollars.[13] It has been assumed that this represents an extreme upper limit on the cost of modifying the Foster Wheeler and Riley Company systems to achieve the proposed standard.

The third scenario (Scenario III) chosen for analysis is the most extreme. This scenario assumes that three manufacturers do not meet the proposed emission limits with their current boilers. In these circumstances the only alternatives available to the manufacturers would be to use the tangential firing system developed by Combustion Engineering or to develop a significantly different combustion system. Since this system is no longer covered by patents, there is no legal or institutional barrier in adapting the Combustion Engineering technology. However, to use this technology the manufacturers would have to undergo major design and fabrication efforts and in all probability would not be able to compete effectively in the market until designs were perfected. While there are potentially large costs associated with this retooling operation, the magnitude of these costs cannot be estimated. As explained in Section 8.4, the potential loss of market share for an extended period of time would far exceed any costs of retooling. The economic implications of these design changes on industry structure will be discussed in Section 8.4.

In addition, there are some minor peripheral considerations such as operator training costs for operation with less excess air; but considering that this standard will apply only to new units which will be incurring operating training costs anyway, these incremental costs will not be significant.

8.3 COSTS OF OTHER ENVIRONMENTAL CONTROLS

The electric utility industry is subject to many environmental regulations other than those related to air pollution. The purpose of this section is to summarize the expected capital and operating requirements imposed on the industry as a whole and on a typical new utility boiler. Unless otherwise noted all costs are taken from "The Economic Impact of EPA's Air and Water Regulations on the Electric Utility Industry."[14]

8.3.1 Environmental Control Costs for Typical New Installations

As was shown in Figure 8-5 the newly installed coal-fired units are currently averaging slightly over 500 megawatts. Consistent with this, a 600 MWe coal-fired unit was selected as the model new utility boiler. This plant is assumed to require chemical effluent treatment, a cooling tower, and entrainment screens for water pollution control.

Table 8-4 shows the estimated capital and operating cost for these devices.

8.3.2 Total Industry Environmental Control Costs

Table 8-5 shows the total capital costs attributable to environmental control costs in the electric utility industry for the period 1975-1985. The estimated cumulative total operating and maintenance costs associated with this equipment between 1975 and 1985 is 6.1 billion dollars. In addition to these costs an estimated 1.0 billion dollars will be required to provide for capacity losses due to the operation of water pollution control equipment.

Table 8-4. ENVIRONMENTAL CAPITAL COST FOR NEW PLANTS[a]

(1975 dollars)

Control Device	Cost/kW	Total Cost (10^6\$)	Annual O&M Costs (Mills/kWh)
Chemical Effluent Treatment	1.52	.9	.3
Mechanical Cooling Tower	5.77	3.46	.2
Entrainment Screens	4.08	2.45	.1
Total	11.37	6.81	.6

[a] Based on a new 600-MW coal-fired unit.

Table 8-5. CAPITAL EXPENDITURES 1975-1985 BY TYPE OF POLLUTION CONTROL EQUIPMENT (excluding equipment built for reasons other than compliance with federal regulations)

	Amount Built (million kWe)	Capital Expenditures (billion 1975 dollars)
Water Regulations		
Chemical Treatment	469.1	$1.2
Cooling Towers	102.2	2.6
Entrainment Screens & Cooling Towers	13.4	0.6

8.4 ECONOMIC IMPACT OF ALTERNATIVE EMISSION CONTROL SYSTEMS

8.4.1 Penetration of New Units

Since the nature of the proposed emission control change involves a potential process change, the economic impacts will tend to accrue in proportion to the introduction of the affected units in the U.S. power generation base. As a result the economic impacts will increase annually as these units come on line and become an increasingly larger percentage of the industry's generating capacity. The long lead times between the initial contracting for a large fossil-fired boiler and the initial commercial operation create a natural lag in measuring the economic and technological impacts of standards which affect these units. For example, units which were designed subsequent to the original NO_x standard in 1971 are only now coming on line. Units affected by this revision of the standard would not be coming into service until the early to mid-1980's. Table 8-6 projects the percentage of total electrical power supplied by units potentially affected by this standard. The total additions of coal-fired units were extrapolated out to 1990.

Making consistent assumptions about the growth in total generation capability over the same period, the table shows that by 1985 the units affected by this standard will be approximately six percent of the total generation capacity of the electric power industry. The actual energy generated by these units will be a larger percentage of the total energy produced nationally since these units will tend to be more efficient than older units and therefore will be put in service preferentially to older, less efficient units. This will give the newer units a higher capacity

Table 8-6. PENETRATION OF NEW COAL-FIRED UNITS INTO U.S. GENERATING BASE

	Projected[a] Total U.S. Generating Capacity (Gigawatts)	Annual Coal[a] Fired Additions (Gigawatts)	Cumulative Coal-fired Additions from 1982 (Gigawatts)[c]	Percent of Total U.S. Generating Capacity	Percent of Total U.S. Energy Generation
1982	700.1	11.6	11.6	1.6	2.1
1983	735.2	12.2	23.8	3.2	4.2
1984	772.1	12.4	36.2	4.7	6.1
1985	810.9[b]	12.9[b]	49.1	6.1	7.9
1986	851.6	13.5	62.6	7.3	9.5
1987	894.4	14.2	76.8	8.6	11.2
1988	939.3	14.9	91.7	9.8	12.7
1989	986.4	15.7	107.4	10.9	14.2
1990	1035.9	16.5	123.9	12.0	15.6

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[a] Taken from Tables 3-6 and Footnote 15

[b] Extrapolated from Tables 3-6 and Footnote 15 at constant growth factor. References the same as shown on Chapter 3 tables.

[c] From the projections in Table 3-6 in Chapter III, approximately 4.96 percent of this capacity will be to replace retiring units. The remainder goes toward net system expansion.

factor than the system average. We have assumed a 65 percent capacity factor for a new base load coal-fired plant (5694 hours/year) compared to overall system capacity factors of 50 percent. Using a rough calculation for the first few years, this factor would increase the impact of this penetration by approximately 30 percent $(\frac{65 \text{ percent}}{50 \text{ percent}})$. This explains the last column in Table 8-6. These data indicate the considerable lag in economic impact on this industry of a standard which only affects new units as they are put into commercial service.

8.4.2 Scenario I Impacts

The economic impacts from Scenario I are by definition negligible. This scenario presumes that all four manufacturers are able to meet the lower NO_x standard on large coal-fired boilers with their existing designs incorporating staged combustion techniques and operated at controlled levels of excess air. There are no design changes or efficiency losses associated with this scenario and consequently there are no direct costs of control. There are some minor peripheral considerations such as operator training costs for operation with less excess air, but considering that this standard will apply only to new units which will be incurring operating training costs anyway, these incremental costs will not be significant.

Test data on several units (see Chapter 6) indicate that this scenario is the most likely to occur.

8.4.3 Scenario II Impacts

This scenario presumes all four manufacturers are able to meet control limits when firing coal with little potential for causing tube wastage, but Foster Wheeler and Riley will have to develop a low NO_x burner for use when firing coal with a high potential for causing tube wastage. Possible economic impacts resulting from this situation are the extra research and development costs associated with designing a low NO_x burner.

Research and development costs for designing a new burner are not expected to be more than two million dollars (see Section 8.2). For Foster Wheeler, this is 11.5 percent of their research and development budget for 1976 and less than 0.2 percent of total sales (see Section 8.1, Table 8-2). It is reasonable to believe that this cost would not have a significant impact on Foster Wheeler's financial situation, for if such research and development efforts were recovered in the first year the burner is put into operation, the increase in price would be less than 1.0 percent.

The situation poses a somewhat different and possibly significant problem to the Riley Company. Riley's research and development budget for 1976 was 2.5 million dollars, and is projected to be 1.8 million dollars for 1977. The reason for the decrease is a slowdown on coal gasification research. Increased costs of two million dollars would more than double the research and development budget in 1977. While this may be viewed as a serious problem, there are several mitigating circumstances. Should the 1977 research and development budget escalate to 3.8 million dollars, research and development expenditures as a percent of total sales (projected to be 242 million dollars in 1977) would be 1.6 percent. Overall, industry research and development expenditures as a percent of total sales is also 1.6 percent. Another mitigating factor is the current research Riley is conducting in low NO_x burner design for its Turbofurnace.[17] These new burners are designed to control mixing of fuel and air to reduce thermal and fuel NO_x. It is quite possible that Riley would not need to spend the full two million dollars specified in order to develop a burner that can meet the proposed standard. Foster Wheeler is also currently engaged in research to develop a new low NO_x burner, so there is a possibility that both companies may not have to spend a full two million dollars to perfect a new, low NO_x burner. With or without this possibility, the economic impact of increased research and development expenditures by both Foster Wheeler and Riley should not be significant.

8.4.4 Scenario III Impacts

The most serious economic impact that could evolve from this standard involves the inability of one or more suppliers to provide a unit which will meet the standard even with the modifications discussed in Scenario II. As has been noted all suppliers appear to be able to meet the proposed lower standard. However, if the results of the other suppliers' new units (designed since the 1971 standard) are such that they cannot or will not guarantee the lower standard, the impacts on the marketplace could be significant.

If a supplier whose current design did not meet the standard chose to adopt a tangentially-fired design he would face two obstacles:

1. The length of time and cost associated with redesign effort;
2. Reluctance on the part of the electric power industry to buy the design from a supplier who had not been offering it previously.

On the first point, without anticipating the need to make such a major redesign effort, a supplier effectively is likely to be "out of the market" for the period of the redesign effort. The potential damages that could accrue from producing and selling a unit that failed to meet the standard could be very high if they involve plant shutdowns or major reductions in efficiency by dropping preheat temperatures. If a supplier chose not to take these risks and instead redesign to a tangentially-fired unit, he would incur not only the costs of the redesign and retooling, but for the period of time the redesign takes, he would be trying to secure orders without the support offered by "typical" drawings and other technical documentation for the design he was offering. Similarly, performance and construction guarantees for the new design for the most part would be unsubstantiated. With the relatively long lead times between the order date and the shipment date for a large coal-fired boiler it is not likely that even a six-month redesign effort would create a period when a supplier could not meet a shipment date as a result of the redesign effort. Although design and manufacturing drawings may be later in the manufacturing process for some parts of the units, the parts would probably still be shipped in time to meet any normal construction schedules. Several factors could complicate this; for example, the power generation business is cyclical. As shown in Section 8.1 the industry has been in a sales "trough" since 1974, and in the past year has just begun to climb slowly out of it. If a sudden rush in orders (typical in this business) occurs at the same time as a major redesign effort, a supplier may have to forego bids that are decided on a short-cycle installation basis.

It is important to distinguish between the type of dislocation being produced here and the design changes that occur as the normal evolution of the product. In the latter case the design changes tend to be logical extrapolations of previous designs which are introduced in a carefully timed and coordinated fashion. The redesign involved in going from opposed wall firing to tangential firing is not only more radical but also could not be timed for the most opportune entry into the market.

The other obstacle involved with such a redesign effort concerns buyer behavior. As Table 8-6 showed, there are only 20 to 25 new coal-fired units being added per year out to the early 1980's. Since many of these are multiple-unit purchases there may be as few as 10-15 discrete purchase decisions per year. (This assumes a noncyclical market and sales of units in a year occurring at the same approximate pace that units are put in service.) Considering that the "average" utility might not be in the market more frequently than every few years, these purchase decisions are not only few in number but also likely to vary considerably in their decision criteria. There are, of course, factors which tend to make these decisions more homogenous, such as the broad regulation in the industry and all-company competition in the same capital market environment. However, it is still very difficult to depict a typical purchase decision for a large coal-fired boiler. Different utility companies will have different criteria and methodology for making the decision, and there are so few data points (as a result of the low number of transactions) that it is impossible to do statistical analysis. These characteristics of the market place preclude the use of elasticity considerations in evaluating such a highly differentiated product.

In conclusion, it is difficult if not impossible to anticipate the market reaction to one of the non-tangential manufacturers to convert over to tangential design. Some utilities may perceive this as a harmless change; others may penalize such an offering for the likelihood of "learning curve" problems often associated with radical redesign efforts. Even though this difficulty exists it is possible to assess some of the impacts if they were to occur. Table 8-7 shows that a change in sales billed equivalent to one sale involving two 600 megawatt coal-fired units would greatly impact any of these companies' share of the coal-fired market. The fact that in the future the coal-fired market is likely to be significantly larger relative to other fossil-fuel fired markets may tend to overstate these numbers; but at the same time this large coal-fired market proportionally increases the likelihood of occurrence of an order being placed as a result of these design considerations.

Table 8-7. RELATIVE IMPACT OF SHIFTING ONE TWO-UNIT (600 MW) ORDER ON EACH BOILER SUPPLIER

Company	Percent of Annual Coal-Fired Megawatts[a]	Percent of Annual Revenues[b]
Combustion Engineering	23%	4.2%
Babcock & Wilcox	25%	4.7%
Foster Wheeler	88%	6.9%
The Riley Company	150%	31.9%[c]

[a] Based on 5-year running average of coal-fired installation in 1978 (see Figure 8-7).

[b] Assuming $50/kW projected price and compared to 1975 reported revenues (not limited to coal-fired sales).

[c] This data point may be somewhat inconsistent since the Riley Company has not historically competed for the 600 MW size unit.

The comparison of the revenues from one such order to the total revenues of the company reflects both the size and the diversity of the four suppliers. The Riley Company is clearly the most vulnerable by this measure; however, this impact is mitigated somewhat by the fact that

Riley to some extent is segmented away from the other suppliers and therefore may be less likely to lose any given order as a result of redesign considerations.

By way of summary, it is difficult to predict the possible market share effects of one or all three non-tangentially-fired suppliers converting their combustion system design. It is not likely that purchasers would devalue such a bid on the basis of capital cost or efficiency since these are not likely to change significantly; however, they may penalize such bids for some period of time on the basis of possible forced outage rate impacts or construction delays associated with such radical redesign efforts. If such is the case and market shares are indeed shifted as a result of such redesign, the impacts could be very severe, especially on the two smaller, less diversified companies.

8.4.5 Modified/Reconstructed Facilities

The proposed standard is not to be applied on a retrofit basis. Only new units which commenced construction on or after the date of proposal of these regulations will be affected. It is not anticipated that any existing units will meet the requirements of being classified as modified or reconstructed units as delineated in Chapter 5 of this standard support document. As a result there will be no economic impact on modified or reconstructed facilities.

8.5 POTENTIAL SOCIOECONOMIC AND INFLATIONARY IMPACT

8.5.1 Inflationary Considerations

All three scenarios do not have the potential for having any direct inflationary impacts. Even under the most radical scenario, that of all manufacturers being forced to use tangential design, the costs would only be in redesign and retooling efforts. These costs, when passed along over a long period of time (attributable to the slow penetration of units affected by this standard) should prove to be minimal and non-inflationary.

8.5.2 Energy Considerations

None of the three scenarios discussed entail any efficiency losses. Consequently, the impact of the proposed standard on energy consumption would be insignificant.

8.5.3 Secondary Socioeconomic Impacts

Clearly, Scenarios I and II could not involve any significant second order impacts to society. The only concern over adverse socioeconomic impacts centers on Scenario III. The differential impact on the four key suppliers in this industry could have significant impacts on the industry structure. The industry by its nature is already highly concentrated. Any circumstance that might tend to concentrate it further may have serious long-term impacts.

8.6 SUMMARY

There will be no additional cost of compliance under the most likely scenario since compliance is achieved by changing the structural configuration of the boilers, not by adding control equipment. Therefore, with no additional outlays, there will be no inflationary pressures generated nor will there be any consumer cost increases. The small business section will suffer no deleterious effects since none of the four companies involved are in that category. Energy requirements will not increase. If anything, with the lowered ratio of excess air, there may be a very slight decrease.

REFERENCES FOR CHAPTER 8

1. Experience sheets, Foster Wheeler Corp., Babcock and Wilcox Co., The Riley Company, Combustion Engineering, Inc., Emissions Standards and Engineering Division, Office of Air Quality Planning and Standards, U.S. Environemntal Protection Agency, Research Triangle Park, North Carolina, 1976.

2. Federal Power Commission, *Electric Power Statistics*, December, 1974, Table 4, page 14, and Edison Electrical Institute, Annual Electric Power Survey.

3. Kidder Peabody Co., *A Status Report on Electric Utility Generating Equipment, Fossil Boilers as of December 31, 1976*, March, 1977.

4. FPC, *Op. cit.*, Table 15, page 14. December 13 and August 31, numbers were averaged to get annual representation.

5. *Ibid.* Table 14 and Table 15, page 14. Capacity factor is calculated by dividing dependable capacity (converted to kWh) by annual energy.

6. *Op. cit.*, Experience Sheets.

7. Ibid.

8. Security Exchange Commission, Form 10K, Foster Wheeler Corp., Babcock and Wilcox Co., The Riley Company, Combustion Engineering, Inc., 1976.

9. *Ibid.*

10. *Ibid.*

11. *Ibid.*

12. *Ibid.*

13. Meeting Notes, Meeting with Babcock and Wilcox Co., Barberton, Ohio, October 1976.

14. "The Economic Impact of EPA's Air and Water Regulations on the Electric Utility Industry," Temple, Barker and Sloane, Inc., prepared for EPA under Contract No. 68-01-2803, March, 1976.

15. Unpublished calculations or data, Emission Standards and Engineering Division, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina.

16. FPC, op cit.

17. "NO_x Control Review," United States Environmental Protection Agency, Fall, 1977, page 5.

9. RATIONALE FOR THE PROPOSED STANDARD

This Background Information document supports proposed nitrogen oxides (NO_x) emission limits for the combustion of pulverized coal (except lignite and coal refuse) in new electric utility steam generating units with heat input rates greater than 73 MW (250 million Btu per hr). The proposed NO_x emission limits for units which burn lignite,[1,2,3,4] coal refuse,[5,6,7] liquid and gaseous fuels,[8,9,10] shale oil, and fuels derived from coal[11,12,13,14,15] are based on other studies, as referenced, and are not discussed in this document. Additional information may be found in the preamble and regulation for Subpart Da in the Federal Register.

Also, all information EPA used in developing the proposed regulation may be found in the Subpart Da docket (number OAQPS-78-1) at the EPA Central Docket Section (A-130), Room 2903B, Waterside Mall, 401 M Street S. W., Washington, D. C. 20460.

9.1 SELECTION OF SOURCE FOR CONTROL

Electric utility steam generating units contribute significantly to national emission levels of nitrogen oxides (NO_x). In 1976 total nationwide emissions of NO_x amounted to about 23.0 teragrams (25.5 million tons); electric utility units acounted for 29 percent of this, or 6.67 teragrams (7.35 million tons). The total capacity of all U. S. units was about

340 gigawatts in 1975 and is expected to rise to 470 gigawatts by 1985, representing a capacity increase of 38 percent in only 10 years. About 250 new units are expected to commence operation during this period.

Due to high emission levels and a strong growth rate, the electric utility industry will continue to be a major source of nationwide NO_x emissions in the future, second only to mobile source emissions. Consequently, EPA believes there is an important need to control NO_x emissions from electric utility steam generating units.

9.2 SELECTION OF POLLUTANTS AND AFFECTED FACILITIES

Electric utility units emit three major pollutants into the atmosphere: sulfur dioxide, particulates, and NO_x. Regulations have been developed for sulfur dioxide and particulates, and these are supported in separate Background Information documents.[16,17] Other air pollutants, including carbon monoxide, and hydrocarbons are also emitted by electric utility units. The quantities of these emitted into the atmosphere, however, are small.

The affected facility to which the proposed emission limits would apply would be defined as any steam generating unit which:

> is located in an electric utility power plant;
>
> is capable of combusting greater than 73 MW (250 million Btu/hr) of fossil fuel either alone or in combination with other fuels; and
>
> commenced construction or modification on or after the date of proposal of these emission limits in the FEDERAL REGISTER.

The proposed regulations would only cover steam generating units which are located in electric utility power plants since study of emission controls for industrial units would require a different economic analysis. Also, different control technology may be needed for industrial units. Industrial units of more than 73 MW (250 million Btu/hr) heat input are presently covered under Subpart D for fossil-fuel-fired steam generators, and studies are in progress to develop revised emission limits for these types of units.

Although the proposed emission limits are primarily concerned with the combustion of fossil fuels, the regulations would also cover new units which burn other fuels either alone or in combination with fossil fuels. A proration equation is included in the regulation which would simplify the determination of an appropriate emission limit when a combination of fuels is burned simultaneously in the same unit.

9.3 SELECTION OF THE BEST SYSTEM OF CONTINUOUS EMISSION REDUCTION CONSIDERING COSTS

NO_x emissions are controlled by modifying the way the fuel is combusted in the boiler. EPA believes that the best system for control of NO_x emissions from electric utility steam generating units which burn pulverized coal is a combination of staged combustion, low excess air, and reduced heat release rate. These combustion modification techniques are basically the same as those needed to achieve the original NO_x emission limits for steam generators under Subpart D. The costs associated with greater implementation of these combustion modification techniques, as needed to comply with the revised NO_x emission limits under Subpart Da, would be minimal. Another emission control technique, flue gas treatment, has not yet been demonstrated effective for reducing NO_x emissions from coal-fired units.

There are several potential side effects associated with operation of a unit at NO_x levels as low as the proposed limits. These are: boiler tube wastage; slagging; increased emissions of particulates, carbon monoxide, polycyclic organic matter, and other hydrocarbons; boiler efficiency losses; carbon loss in the ash; low steam temperatures; and operating hazards (including boiler explosions). EPA has evaluated these side effects and believes that none would be a problem during operation of a boiler at the NO_x levels required by the proposed emission limits. Concern over several of the potential side effects, however, including tube wastage, slagging, increased emissions of polycyclic organic matter and particulates, and possible operating hazards has been expressed by industry. These concerns are responded to below.

Tube wastage (or corrosion) is the deterioration of boiler tube surfaces due to the corrosive effects of ash in the presence of a reducing atmosphere. (A reducing atmosphere often accompanies low NO_x operation). The severity of tube wastage is believed to vary with several factors, but especially with the quality of the coal burned. For example, high sulfur Eastern coals are believed to cause more of a tube wastage problem than low sulfur Western coals. Serious tube wastage can shorten the life of a boiler and result in expensive repairs.

Concern over tube wastage is reflected in a statement made by one of the four major boiler manufacturers, Combustion Engineering, that it would guarantee its new units to meet an NO_x limit of 210 ng/J (0.5 lb/million Btu) when burning low sulfur, low rank Western coals, but only 260 ng/J when burning the higher sulfur Eastern bituminous coals (see Appendix C). The other boiler manufacturers and several electric utilities have also expressed concern over the potential for tube wastage with high sulfur Eastern coals.

Corrosion test results are available for five of the six units EPA tested in support of the proposed emission limits. These tests involved the measurement of metal loss from test coupons inserted into the boiler. The results indicate that corrosion was not a serious problem for at least four of the units during the testing. These were all tangentially-fired boilers manufactured by Combustion Engineering. It should be noted, however, that coupon corrosion tests indicate only relative corrosion rates in selected areas of a boiler and do not demonstrate what the long-term effects of corrosion would be on the life of a unit.

EPA believes that new units which would be designed to comply with the proposed NO_x emission limits would not experience serious tube wastage for the following reasons:

> Coupon corrosion tests indicate that tube wastage is not significantly accelerated during low NO_x operation of modern Combustion Engineering boilers.
>
> Combustion Engineering has stated that its modern units would be capable of achieving, without adverse long-term side effects, a 260 ng/J (0.60 lb/million Btu) emission limit when burning Eastern bituminous coals and 210 ng/J (0.50 lb/million Btu) when burning lower rank Western coals and lignite. These are essentially the same limits as those proposed by EPA.
>
> Foster Wheeler and Babcock & Wilcox have executed contracts to build units which will be required to comply with the State of New Mexico's NO_x emission limit of 190 ng/J (0.45 lb/million Btu).
>
> Babcock & Wilcox has designed a new burner which will permit a furnace to be maintained in an oxidizing environment, thus, minimizing the potential for furnace wall corrosion when high sulfur bituminous coal is burned.
>
> Foster Wheeler and Riley Stoker are developing new burners which may have the same advantage as the new Babcock & Wilcox burner. Also, Foster Wheeler incorporates "boundary air" in its modern units to minimize reducing conditions near the boiler wall where tube wastage occurs.

Unmanageable slagging was not reported during any of the EPA emission tests conducted in support of the proposed limits. Based on the boiler manufacturers' experience with high slagging coals, EPA believes that modern units which are designed with ample furnace volumes would minimize slagging while complying with the proposed emission limits.

Polycyclic organic matter (POM) is a concern because some types of POM have been identified as possible carcinogens. EPA has POM emission data from only one unit. This is an old-style unit, however, and its emissions are probably not representative of emissions from modern-design units. It is reasonable to believe that POM emissions should not increase on modern units because POM generation is closely related to incomplete combustion, and poor combustion was not apparent during the EPA tests. This is evidenced by CO emission levels which were generally the same during normal and low NO_x operation. Also, electric utility power plants contribute very little (less than one percent) to total nationwide emission levels of POM. Thus, EPA does not believe that POM emission increases will be significant as a result of these revised regulations.

During EPA tests of modern units, particulate emission levels were variable. However, no significant increases in particulate levels were detected which could be directly attributed to boiler operation at low NO_x levels. Consequently, EPA does not believe that particulate emissions would increase as a result of low NO_x operation.

There was no indication during EPA testing that operation of a boiler at the NO_x levels required by the proposed limits could cause boiler operating hazards. During discussions with the boiler manufacturers in 1976, EPA asked if more effective NO_x control would increase safety hazards. The three largest manufacturers indicated that they were not worried about safety hazards at reduced NO_x levels. Based on EPA field experience and discussions with the boiler manufacturers, EPA does not believe that NO_x control would result in serious safety hazards.

9.4 SELECTION OF THE FORMAT OF THE PROPOSED STANDARD

The Clean Air Act Amendments of 1977 require EPA to establish both emission limits and percent reductions in uncontrolled emission levels for new steam generators which burn fossil fuels. EPA has decided to apply these requirements to the combustion of all fuels so as to simplify enforcement and to effect greater environmental benefits.

The proposed emission limits are expressed as mass per unit heat input (nanograms per joule, or pounds per million Btu). In 1971 when emission limits for steam generators were promulgated under Subpart D, EPA determined that units of mass per unit heat input were the most practical of several options. EPA believes that it is still practical to express the proposed revised emission limits for steam generators in terms of these units.

It is impossible to specify a rational percent reduction in uncontrolled NO_x emission levels because there is no direct relationship between NO_x emissions with and without control. Furthermore, since NO_x control with combustion modification techniques occurs in the furnace at the instant that NO_x is formed, there is no way to measure uncontrolled NO_x emission levels prior to combustion. However, to comply with the requirements of the Act, EPA has defined representative uncontrolled emission levels for solid, liquid, and gaseous fuels, and a percent reduction for each fuel has been specified. The defined uncontrolled emission levels are based on worst-case emission rates, according to published emission factors.[18]

The proposed percent emission reduction requirements are as follows:

> A 25 percent emission reduction would be required for gaseous fuels, based on an uncontrolled emission rate defined as 290 ng/J (0.67 lb/million Btu).
>
> A 30 percent emission reduction would be required for liquid fuels, based on an uncontrolled emission rate defined as 310 ng/J (0.72 lb/million Btu).
>
> A 65 percent emission reduction would be required for solid fuels, based on an uncontrolled emission rate defined as 990 ng/J (2.3 lb/million Btu).

If a unit is in compliance with the appropriate NO_x emission limit, then it will automatically satisfy the percent emission reduction requirement. Thus, in the case of NO_x emissions, the percent reduction is not controlling, and compliance testing for the emission limitation will automatically satisfy all compliance testing requirements.

9.5 SELECTION OF EMISSION LIMITS

NO_x emission tests were performed on six modern pulverized coal-fired electric utility steam generating units. Four of these units were new Combustion Engineering designs, one was a Combustion Engineering unit which had been retrofitted with overfire air, and one was a Babcock & Wilcox unit which had been retrofitted with low-emission (dual register) burners. During these tests NO_x emissions were consistently below 260 ng/J (0.60 lb/million Btu) and commonly below 210 ng/J (0.50 lb/million Btu). However, due to the potential for tube wastage associated with low NO_x operation, EPA has concluded that it would not be reasonable to establish an NO_x emission limit for pulverized coal-fired units at 210 ng/J for all types of coal.

As mentioned in section 9.3, tube wastage is of major concern, expecially when Eastern coals are burned. EPA has concluded from field testing results, discussions with industry, and the advice of our research laboratories that an NO_x emission limit of 260 ng/J would be appropriate for new units which burn Eastern coals. At this emission level, EPA believes that tube wastage would not be accelerated as a result of the application of combustion modification techniques.

Tube wastage does not appear to be a problem at emission levels as low as 210 ng/J when low sulfur, low rank Western coals are burned. Consequently, EPA has proposed an emission limit of 210 ng/J for new units which burn these coals. Low sulfur, low rank Western coal would be classified in the proposed regulations as "subbituminous coal," according to ASTM standards. There may be some Western bituminous coals which have high tube wastage potentials due to high sulfur contents. The combustion of these coals would be subject to the same emission limit as Eastern coals.

9.6 VISIBLE EMISSION STANDARDS

There are no visible emission regulations associated with NO_x emissions. An opacity standard has been proposed under Subpart Da, however, and this is described in the Background Information Document for Particulate Matter.[17]

9.7 MODIFICATION AND RECONSTRUCTION CONSIDERATIONS

A modification is defined in 40 CFR Part 60, Subpart A and in section 111 of the Clean Air Act as any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies. Upon modification, an existing facility becomes an affected facility (i.e., it becomes subject to new source performance standards) for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere. Certain exceptions to the modification rule are explained in

Subpart A and in Chapter 5. Also, Chapter 5 discusses several situations where changes to the pulverizer system, combustion air system, steam generation system, draft system, or fuel combustion system could cause an increase in emissions, and thus, cause a facility to be subject to the modification rule.

A reconstruction is defined in Subpart A as the replacement of components of an existing facility to such an extent that:

> The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility; and
>
> It is technologically and economically feasible to meet the applicable emission standards.

An existing facility, upon reconstruction, becomes an affected facility (i.e., it becomes subject to new source performance standards) irrespective of any changes in emission rates. The reconstruction rule is further defined in Subpart A.

Rather than modifying or reconstructing old units, electric utilities generally prefer to transfer these units from base load to standby status. Newer and more efficient units then assume base load responsibility. Consequently, it is probable that few existing utility steam generating units will be modified or reconstructed in the future.

9.8 SELECTION OF MONITORING REQUIREMENTS

The proposed regulations for NO_x require that an initial performance test be performed just after startup of a new electric utility unit. Once the performance test has been successfully completed, continuous compliance with the proposed emission limits would be required during the life of the unit.

The initial performance test, as prescribed in section 60.8 of 40 CFR Part 60, Subpart A, would be conducted within 60 days after achieving the full load at which a new unit would be operated, but not later than 180 days after initial startup of the unit. Compliance would be determined by averaging emissions over a 24-hour daily period, from midnight to midnight. The 24-hour daily period would be assumed to constitute three 8-hour runs, thereby satisfying the requirement under §60.8 that a performance test consist of the average of 3 separate runs.

Following the initial performance test, continuous compliance with the proposed emission limits would be required during the life of the unit. Compliance would be determined by averaging all emission data recorded for each 24-hour period. Each 24-hour period would constitute a separate performance test, and the owner or operator of a unit would be required to report emissions in excess of the proposed limits. The continuous compliance requirement would not apply during startup and shutdown of a unit.

The decision to select an averaging period of 24 hours for continuous compliance with the proposed emission limits is supported with continuous monitoring emission data from a modern unit in the Western U. S. which burns subbituminous coal. These data indicate that NO_x emissions can be successfully monitored on a continuous basis, and that emissions averaged over a 24-hour period would not exceed the proposed emission limits.

Compliance with the proposed emission limitations would automatically assure compliance with the required percent reduction in uncontrolled emission levels. Thus, the percent reduction would not require performance testing.

EPA believes that continuous compliance with the proposed emission limits is important to assure continuous operation of a boiler at low NO_x levels. All testing would be performed according to procedures described in Subpart Da and Reference Method 19.

9.9 SELECTION OF PERFORMANCE TEST METHODS

A continuous monitoring system which meets Performance Specification #2 for oxides of nitrogen and Performance Specification #3 for oxygen or carbon dioxide, as described in 40 CFR Part 60 Appendix B, would be required for performance testing. In addition, the zero and calibration span drift of the monitors must be checked and monitoring data reported according to procedures described in Appendix D (D.3) of this document and in Reference Method 19.

Although departures were made from the performance specification procedures during EPA testing, sufficient care was taken to assure that the departures did not adversely affect the test results.

REFERENCES FOR CHAPTER 9

1. Standards Support and Environmental Impact Statement, Volume 1: Proposed Standards of Performance for Lignite-Fired Steam Generators. Emission Standards and Engineering Division, Office of Air Quality Planning and Standards, U. S. Environmental Protection Agency. Research Triangle Park, North Carolina. Report Number EPA-450/2-76-030a. December, 1976. 190 p.
2. U. S. Environmental Protection Agency. Proposed amendments to Standards of Performance for New Stationary Sources (Lignite-Fired Steam Generators). 40 CFR part 60, Subpart D. Washington, D. C. Federal Register (41 FR 55792). December 22, 1976. 3 p.
3. Standards Support and Environmental Impact Statement, Volume 2: Promulgated Standards of Performance for Lignite-Fired Steam Generators. Emission Standards and Engineering Division, Office of Air Quality Planning and Standards, U. S. Environmental Protection Agency. Research Triangle Park, North Carolina. Report Number EPA-450/2-76-030b. November, 1977. 30 p.
4. U. S. Environmental Protection Agency. Promulgated amendments to Standards of Performance for New Stationary Sources (Lignite-Fired Steam Generators). 40 CFR Part 60, Subpart D. Washington, D. C. Federal Register (43 FR 9276). March 7, 1978. 3 p.
5. U. S. Environmental Protection Agency. Promulgated amendments to Standards of Performance for New Stationary Sources (Coal Refuse). 40 CFR Part 60, Subpart D. Washington, D. C. Federal Register (40 FR 2803). January 16, 1975. 1 p.

6. Test Report on Nitrogen Oxide Emission from Unit No. 1 at Southern Illinois Power Cooperative, Marion, Illinois (Corrected). Burns and McDonnell. Kansas City. Missouri. Project Number 73-108-1-000. Test Dates: July 30 - August 2, 1974. 25 p.

7. Review of Burns and McDonnell Report on GOB Pile Burner NO_x Emissions. Internal EPA Memorandum, Tom Logan to Don R. Goodwin. September 20, 1974.

8. Background Information for Proposed New Source Performance Standards: Steam Generators, Incinerators, Portland Cement Plants, Nitric Acid Plants, and Sulfuric Acid Plants. Office of Air Programs, U.S. Environmental Protection Agency. Research Triangle Park, North Carolina. Report Number APTD-0711. August, 1971. 54 p.

9. U. S. Environmental Protection Agency. Proposed Standards of Performance for New Stationary Sources. 40 CFR Part 60, Subpart D. Washington, D. C. Federal Register (36 FR 15704). August 17, 1971. 19 p.

10. U. S. Environmental Protection Agency. Promulgated Standards of Performance for New Stationary Sources. 40 CFR Part 60, Subpart D. Washington, D. C. Federal Register (36 FR 24876). December 23, 1971. 20 p.

11. Fuel Gas Environmental Impact: Phase Report. Industrial Environmental Research Laboratory, Office of Research and Development, U. S. Environmental Protection Agency. Research Triangle Park, North Carolina. Report Number EPA-600/2-75-078. November, 1975. 314 p.

12. Burner Design Criteria for NO_x Control from Low-Btu Gas Combustion, Volume 1: Ambient Fuel Temperature. Industrial Environmental Research Laboratory, Office of Research and Development, U. S. Environmental Protection Agency. Research Triangle Park, North Carolina. Report Number EPA-600/7-77-094a. August, 1977. 119 p.

13. Burner Design Criteria for NO_x Control from Low-Btu Gas Combustion, Volume II: Elevated Fuel Temperature. Industrial Environmental Research Laboratory, Office of Research and Development, U. S. Environmental Protection Agency. Research Triangle Park, North Carolina. Report Number EPA-600/7-77-094b. December, 1977. 84 p.

14. Preliminary Environmental Assessment of Combustion Modification Techniques, Volume II: Technical Results. Industrial Environmental Research Laboratory, Office of Research and Development, U. S. Environmental Protection Laboratory. Research Triangle Park, North Carolina. Report Number EPA-600/7-77-119b. October, 1977. 578 p.

15. Characteristics of Solvent Refined Coal: Dual Register Burner Tests. Electric Power Research Institute. Palo Alto, California. Report Number EPRI FP-628. January, 1978. 109 p.

16. Electric Utility Steam Generating Units: Background Information for Proposed Sulfur Dioxide Emission Standards. Emission Standards and Engineering Division, Office of Air Quality Planning and Standards, U. S. Environmental Protection Agency, Research Triangle Park, North Carolina. Report Number EPA 450/2-78-007a. July, 1978.

17. Electric Utility Steam Generating Units: Background Information for Proposed Particulate Matter Emission Standards. Emission Standards and Engineering Division, Office of Air Quality Planning and Standards, U. S. Environmental Protection Agency, Research Triangle Park, North Carolina. Report Number EPA-450/2-78-006a. July, 1978.

18. Compilation of Air Pollutant Emission Factors (Second Edition). Monitoring and Data Analysis Division, Office of Air Quality Planning and Standards, U. S. Environmental Protection Agency, Research Triangle Park, North Carolina. Report Number AP-42. February, 1976. Two Parts, 462 p.

APPENDIX A

EVOLUTION OF PROPOSED STANDARDS

A.1 GENERAL

New source performance standards for NO_x emissions from steam generators of more than 73 megawatts (250×10^6 Btu/hr) heat input were proposed on August 17, 1971, and were promulgated December 23, 1971, under authority of the Clean Air Act of 1970. The foregoing Act provided that the Administrator should, from time to time, revise these standards. During 1975 it was decided that there were enough new developments in control of NO_x emissions from large steam generators to warrant considering revising these standards. The new developments were, that although no new techniques had been developed sufficiently since 1971 to warrant consideration for new source performance standards, it appeared that the NO_x control techniques recommended for achievement of the 1971 standards were more effective than originally projected. Consequently, the investigation was purposely directed toward determining if NO_x emission limits lower than the 1971 limits should be recommended.

At the onset, consideration of standards for lignite-fired steam generators was eliminated because standards development for this category of sources was nearly complete.

The study was initiated in late 1975 by making a thorough literature search of the thousands of references of the Air Pollution Technical Information Center of the U. S. Environmental Protection Agency (EPA). In January, 1976, the engineering staff of the EPA activity responsible for recommending new limits (Office of Air Quality Planning and Standards) met with the engineering staff of the EPA activity responsible for research and development (Control Systems Laboratory, now called the

Industrial Environmental Research Laboratory). Important parts of the data base used to recommend revised NO_x control limits were obtained from the Industrial Environmental Research Laboratory (IERL).

The data provided by IERL were sufficient to warrant further work on standards revision. The foregoing preliminary study showed that at the end of 1975 there were no sources on line which were subject to the standards which became effective in 1971. This was because of the five-year lead time between commencement of construction of a large steam generator and activation of the unit. IERL advised, however, that there were several Combustion Engineering units and that there was one Babcock and Wilcox unit on line which, although not subject to the 1971 standard, were designed similar to the coal-fired steam generator designs which were being furnished to achieve the 1971 standard. IERL had data which showed these units were capable of controlling NO_x emissions to levels substantially below the limit of 300 nanograms per joule (0.07 lb/10^6 Btu) of the 1971 standard. There were no similar data for large oil or gas-fired steam generators.

Separate meetings were arranged with Babcock and Wilcox, Combustion Engineering, Inc., Foster Wheeler Energy Corporation, and Riley Stoker Corporation which, in total, furnish nearly all of the large steam generators installed in the United States. These meetings occurred in February, 1976, and indicated to EPA that all of the four manufacturers were capable of furnishing coal-fired steam generators which limit NO_x emissions to levels substantially less than the 300 nanogram per joule (0.07 lb/10^6 Btu) limit promulgated in 1971.

In February, 1976, the tangential designs of Combustion Engineering, Incorporated, were the best established because several Combustion Engineering units were on line which had been tested at low NO_x levels. There was one Babock and Wilcox unit on line which was an old style unit equipped with new specially designed burners and which was equally effective in limiting NO_x emissions. Neither Foster Wheeler or Riley Stoker had any of their newest designs on line. All four manufacturers said more new design coal-fired steam generators would be coming on line during 1976 and subsequent years.

All of the four manufacturers indicated concern about potential adverse side effects of NO_x control, such as corrosion, loss of boiler efficiency, high CO, etc. (See Chapter 4 and 6.) Only Combustion Engineering said they were confident their designs could achieve low NO_x emission levels without adverse side effects. The other three boiler manufacturers were uncertain and said they needed more experience.

Subsequent to the February, 1976, meeting with the four boiler manufacturers, a comprehensive data base was gathered based on the work of IERL prior to February, 1976. This data base was supplemented by IERL data and by Combustion Engineering data furnished later in 1976.

In November, 1976, EPA met with the National Air Pollution Control Techniques Advisory Committee in San Francisco. At this meeting EPA advised the Committee of plans to revise the NO_x standard for large coal-fired steam generators from the 1971 limit of 300 nanograms per joule (0.7 $lb/10^6$ Btu) to a new limit of 260 nanogramss per joule (0.6 $lb/10^6$ Btu) for all large solid fuel-fired sources except lignite-fired sources. The concensus of the Committee was that the lower limit was feasible. The four boiler manufacturers expressed positions similar to the positions already discussed in conjunction with the February, 1976, meetings. In summary, Combustion Engineering said they were ready to achieve the lower limit. The other three manufacturers said they would like more time.

EPA work on NO_x standards revision was limited during the period between the November, 1976, National Air Pollution Control Techniques Advisory Committee Meeting, and August, 1977. This was because it was decided that it would be more efficient to propose changes in the NO_x standard at the same time as proposing revisions to the particulate and SO_2 standards. Work on revising the particulate and SO_2 standards was not as far advanced as the NO_x standards revision project.

Another major change occurred in August, 1977, when the Clean Air Amendments of 1977 were enacted. The Clean Air Act of 1970 provided for NO_x standards revision based on EPA judgment. The 1977 amendments mandated that the standards be revised.

Further results of IERL emission and corrosion testing of tangentially-fired units and test results of Babcock and Wilcox units equipped with specially designed burning were added to the data base during 1977. It was also learned that Babcock and Wilcox and Foster Wheeler had contracted to each furnish a large coal-fired steam generator for the San Juan Station of Public Service Company of New Mexico. These units were to be subject to the New Mexico NO_x regulation of 190 nanograms per joule (0.45 $lb/10^6$ Btu).

Based on this additional data, EPA decided to revise the original recommendation for solid fuel, other than lignite-fired sources, of 260 nanograms per joule (0.6 $lb/10^6$ Btu) to one of 210 nanograms per joule (0.5 $lb/10^6$ Btu) for large subbituminous coal-fired units and 260 nanograms per joule (0.6 $lb/10^6$ Btu) for all other large solid fuel (except lignite) fired sources. In addition, the recommendations were revised to require a percent emission reduction as stipulated by the Clean Air Amendments of 1977.

During December, 1977, the revised recommendations were reviewed before a Working Group composed of all interested EPA activities and at a separate meeting of the National Air Pollution Control Techniques Advisory Committee. The consensus of the participants of both meetings was that recommendations for proposed NO_x standards were feasible.

During the period between December 1977 and August 1978 further data on control of NO_x emissions from Babcock and Wilcox, Foster Wheeler, and Riley Stoker boilers were incorporated in the document. Limited data was also added on the effect of NO_x control on polycyclic organic matter emissions. Data on continuous monitoring of NO_x emissions was added in February, 1978. Further testing was conducted in April and again in June, 1978 to evaluate the integrity of the NO_x continuous emission monitoring data. Although the final results of the April and June testing are not yet available, preliminary results indicate the data is probably valid.

APPENDIX B

INDEX TO ENVIRONMENTAL IMPACT CONSIDERATIONS

This appendix consists of a reference system which is cross-indexed with the October 21, 1974, Federal Register (39 FR 37419) containing EPA guidelines for the preparation of Environmental Impact Statements. This index can be used to identify sections of the document which contain data and information germane to any portion of the Federal Register guidelines.

CROSS INDEXED REFERENCE SYSTEM TO HIGHLIGHT ENVIRONMENTAL IMPACT PORTIONS OF THE DOCUMENT

Agency Guideline for Preparing Regulatory Action Environmental Impact Statements (39 FR 37419)	Location Within the Standards Support and Environmental Impact Statement
1. Background and description of the proposed action.	
- Describe the recommended or proposed action and its purpose.	The proposed regulations are summarized in chapter 1 (section 1.1) and chapter 9 (section 9.4). The statutory basis for the proposed regulations (section 111 of the Clean Air Act, as amended) is discussed in chapter 2. The purpose of the proposed regulations is discussed in chapter 9 (sections 9.1, 9.2, and 9.4).
- The relationship to other actions and proposals significantly affected by the proposed action shall be discussed, including not only other Agency activities, but also those of other governmental and private organizations.	The relationship of the proposed regulations to other actions and proposals is discussed in chapter 1 (sections 1.1 and 1.2), chapter 7 (section 7.3), and chapter 9 (sections 9.2 and 9.6).
2. Alternatives to the proposed action.	
- Describe and objectively weigh reasonable alternatives to the proposed action, to the extent such alternatives are permitted by the law . . . For use as a reference point to which other actions can be compared, the analysis of alternatives should include the alternative of taking no action, or of postponing action. In addition, the analysis should include	The Clean Air Act amendments of 1977 require EPA to revise existing regulations under section 111 of the Act for fossil-fuel-fired stationary sources. Thus, EPA did not have the option of taking no action or of postponing action. Alternative control systems are discussed in chapter 4 (section 4.2). The environmental impacts of different levels of control are discussed in chapter 7

CROSS INDEXED REFERENCE SYSTEM TO HIGHLIGHT ENVIRONMENTAL IMPACT PORTIONS OF THE DOCUMENT (continued)

Agency Guideline for Preparing Regulatory Action Environmental Impact Statements (39 FR 37419)	Location Within the Standards Support and Environmental Impact Statement
alternatives having different environmental impacts, including proposing standards, criteria, procedures, or actions of varying degrees of stringency. When appropriate, actions with similar environmental impacts but based on different technical approaches should be discussed. This analysis shall evaluate alternatives in such a manner that reviewers can judge their relative desirability.	(section 7.2). The economic impact of alternative control levels and systems are discussed in chapter 8. Alternative formats for the proposed regulations are discussed in chapter 9 (section 9.4).
- The analysis should be sufficiently detailed to reveal the Agency's comparative evaluation of the beneficial and adverse environmental, health, social, and economic effects of the proposed action and each reasonable alternative.	The environmental and energy impacts of the proposed regulations are discussed in chapter 1 (section 1.2), chapter 7, chapter 8 (section 8.5.2), and chapter 9 (section 9.1). Economic impacts are discussed in chapter 1 (section 1.2) and chapter 8. The inflationary impact is discussed in chapter 1 (section 1.3) and chapter 8 (section 8.5.1). The socioeconomic impact is discussed in chapter 8 (section 8.5.3).
	Section 111 of the Clean Air Act does not require EPA to directly consider health effects in establishing the level of new source performance standards. However, the health effects associated with fossil-fuel-fired steam generators were considered in 1971 (36 FR 5931)

CROSS INDEXED REFERENCE SYSTEM TO HIGHLIGHT ENVIRONMENTAL IMPACT PORTIONS OF THE DOCUMENT (continued)

Agency Guideline for Preparing Regulatory Action Environmental Impact Statements (39 FR 37419)	Location Within the Standard Support and Environmental Impact Statement
	when these units were listed as sources which may contribute significantly to air pollution which causes or contributes to the endangerment of public health or welfare.
- Where the authorizing legislation limits the Agency from taking certain factors into account in its decision making, the comparative evaluation should discuss all relevant factors, but clearly identify those factors which the authorizing legislation requires to be the basis of the decision making.	The legislative history of new source performance standards is presented in chapter 2. The proposed regulations are required by the Clean Air Act amendments of 1977, as discussed in chapter 9 (section 9.4).
- In addition, the reasons why the proposed action is believed by the Agency to be the best course of action shall be explained.	The rationale for the proposed regulations is presented in chapter 9 (in particular, sections 9.3 and 9.5).
3. Environmental impact of the proposed action.	
A. Primary impact	
- Primary impacts are those that can be attributed directly to the action, such as reduced levels of specific pollutants brought about by a new standard and the physical changes that occur in the various media with this reduction.	The primary environmental impacts on mass emissions and ambient air quality are discussed in chapter 1 (section 1.2), chapter 7 (section 7.2), and chapter 9 (section 9.1).

CROSS INDEXED REFERENCE SYSTEM TO HIGHLIGHT ENVIRONMENTAL IMPACT PORTIONS OF THE DOCUMENT (continued)

Agency Guideline for Preparing Regulatory Action Environmental Impact Statements (39 FR 37419)	Location Within the Standards Support and Environmental Impact Statement
B. Secondary impact	
- Secondary impacts are indirect or induced impacts. For example, mandatory reduction of specific pollutants brought about by a new standard could result in the adoption of control technology that exacerbates another pollution problem and would be a secondary impact.	Secondary impacts on air and water quality, solid waste disposal, noise, and energy conservation are discussed in chapter 1 (section 1.2), chapter 7 (section 7.3), and chapter 8 (section 8.5.2).
4. Other considerations.	
A. Adverse impacts which cannot be avoided should the proposal be implemented. Describe the kinds and magnitudes of adverse impacts which cannot be reduced in severity to an acceptable level or which can be reduced to an acceptable level but not eliminated. These may include air or water pollution, damage to ecological systems, reduction in economic activities, threats to health, or undesirable land use patterns. Remedial, protective, and mitigative measures which will be taken as part of the proposed action shall be identified.	The potential adverse side effects associated with low NO_x operation are discussed in chapter 6 and chapter 9 (sections 9.3 and 9.5). Potential adverse economic impacts are discussed in chapter 8.

CROSS INDEXED REFERENCE SYSTEM TO HIGHLIGHT ENVIRONMENTAL IMPACT PORTIONS OF THE DOCUMENT (continued)

Agency Guideline for Preparing Regulatory Action Environmental Impact Statements (39 FR 37419)	Location Within the Standards Support and Environmental Impact Statement
B. Relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity. Describe the extent to which the proposed action involves trade-offs between short-term environmental gains at the expense of long-term losses or vice versa and the extent to which the proposed action forecloses future options. Special attention shall be given to effects which pose long-term risks to health or safety. In addition, the timing of the proposed action shall be explained and justified.	Trade-offs are limited to the potential side effects associated with low-NO_x operation. These are discussed in chapter 6 and chapter 9 (section 9.5). The proposed regulations are timed to become effective as quickly as possible.
C. Irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented. Describe the extent to which the proposed action curtails the diversity and range of beneficial uses of the environment. For example, irreversible damage can result if a standard is not sufficiently stringent.	There would be no irreversible and irretrievable commitments of resources as a result of the proposed regulations. See chapter 7.

CROSS INDEXED REFERENCE SYSTEM TO HIGHLIGHT ENVIRONMENTAL IMPACT PORTIONS OF THE DOCUMENT (continued)

Agency Guideline for Preparing Regulatory Action Environmental Impact Statements (39 FR 37419)	Location Within the Standards Support and Environmental Impact Statement
D. A discussion of problems and objections raised by other Federal, State, and local agencies and by other persons in this review process. Final statements (and draft statements if appropriate) shall summarize the significant comments and suggestions made by reviewing organizations and individuals and shall describe the disposition of issues surfaced (i.e., revisions to the proposed action to mitigate anticipated impacts of objections). In particular, they shall address in detail the major issues raised when the Agency position is at variance with recommendations and objections (e.g., reasons why specific comments and suggestions could not be adopted, and factors of overriding importance prohibiting the incorporation of suggestions). Reviewer's statements should be set forth in a "comment" and discussed in a "response." In addition, the source of all comments should be clearly identified and copies of the comments (or summaries where response has been exceptionally voluminous) should be attached to the final statement.	All comments received during the public comment period which follows proposal of the regulations will be responded to in a separate document. This will be available upon promulgation of the regulations.

APPENDIX C

SOURCE TEST DATA

EXHIBIT I

Basic Source Test Data References

1. Crawford, A. R., E. H. Manny, and W. Bartok, The Effect of Combustion Modification on Pollutants and Equipment Performance of Power Generation Equipment, Exxon Research and Engineering Company, Linden, New Jersey, September 1975.
2. Program for Reduction of NO_x from Tangential Coal-Fired Boilers, Phase II, EPA-650/2-73-005-a, Office of Research and Development, U. S. Environmental Protection Agency, Research Triangle Park, North Carolina, June 1975.
3. Selker, A. P., Overfire Air as a NO_x Control Technique for Tangential Coal-Fired Boilers, Combustion Engineering, Incorporated, Windsor, Connecticut, September 1975.
4. Campobenedetto, E. J., The Dual Register Pulverized Coal Burner--Field Test Results, Presented at the Engineering Foundation Conference on Clean Combustion of Coal, Franklin Pierce College, Rindge, New Hampshire, July 31 to August 5, 1977.
5. Overfire Air Technology for Tangentially Fired Utility Boilers Firing Western U. S. Coal, EPA 600/7-77-117, U. S. Environmental Protection Agency, Research Triangle Park, North Carolina, October 1977.
6. Vatsky, J., Attaining Low NO_x Emissions by Combining Low Emission Burners and Off-Stoichiometric Fining, Foster Wheeler Energy Corporation, Livingston, New Jersey, November 1977.

EXHIBIT II

C-E Power Systems
Combustion Engineering, Inc.
1000 Prospect Hill Road
Windsor, Connecticut 06095

Tel. 203/688-1911
Telex 9-9297

C-E POWER SYSTEMS

FOR: John Copeland, Room 754 R U S H
Telecopied October 8, 1976

October 8, 1976

Mr. John Copeland
United States Environmental Protection Agency
Office of Air Quality Planning and Standards
Research Triangle Park
North Carolina 27711

Dear Mr. Copeland:

Would you please include the following disclaimer notice with the data that we sent to you on April 6, 1976, since you are publishing this data verbatim:

LEGAL NOTICE

"This data was prepared by Combustion Engineering, Inc. for the United States Environmental Protection Agency. Combustion Engineering, Inc. nor any person acting on its behalf; (a) makes any warranty or representation, express or implied including the warranties of fitness for a particular purpose or merchantability, with respect to the accuracy, completeness, or usefulness of the information contained in this report, or that the use of any information, apparatus, method, or process disclosed in this report may not infringe privately owned rights; or (b) assumes any liabilities with respect to the use, of, or for damages resulting from the use of, any information, apparatus, method or process disclosed in this report."

Sincerely yours,

COMBUSTION ENGINEERING, INC.

Henry E. Burbach

Henry E. Burbach
Director, Proposition Engineering

HEB:mm

C-E Power Systems
Combustion Engineering, Inc.
1000 Prospect Hill Road
Windsor, Connecticut 06095

Tel. 203/688-1911
Telex: 9-9297

POWER
SYSTEMS

November 11, 1977

Mr. George B. Crane, P.E.
Industrial Studies Branch
Emission Standards & Engineering Division
United States Environmental Protection Agency
Research Triangle Park, North Carolina 27711

Dear Mr. Crane:

The following are our answers to your questions posed in your October 21, 1977 letter:

Question 1: Does C-E maintain their statement made on our visit of February 19, 1977, to guarantee their new boilers to meet a 0.6 lb/10^6 Btu NOx limit with Eastern coals and 0.5 lb limit for other coals?

Answer: Yes, C-E still will maintain this position.

Question 2: Can new C-E boilers meet a 0.5 limit across the board? If so, could C-E so guarantee?

Answer: No, C-E does not feel that 0.5 NOx limit can be met across the board with all fuels.

Question 3: Does C-E know of any feasible way to characterize or describe a "Western" or an "Eastern" coal for purposes of standards setting?

Answer: Characterization of Eastern vs. Western coal can be accomplished by evaluating the coal in the ASTM ranking scale. Those coals which rank higher in heating value than 11,000 Btu/lb on a moist, mineral matter free basis which classify as hi-volatile "C" or sub-bituminous "A" (and above), we would characterize as Eastern coal. Those below 11,000 Btu/lb which are sub-bituminous "B", "C" and lignite would classify as Western coal for this purpose. There are coals found in the Rocky Mountain area which classify as hi-volatile "C", sub-bituminous "A" and above.

Attached is a copy of a C-E standard sheet #61-038 which graphically displays the ASTM ranking.

Question 4: Our trip report (item no. 1) states that C-E "does not recommend tying the limits of a NOx standard to coal analysis". Does C-E maintain this opinion?

Question 4: cont'd

Answer: Yes, we still believe that we can not identify constituents in the fuel and ash analysis sufficiently well to directly relate to a NOx level regulation.

This would be beyond the classification outlined above for item no. 3, where we make a gross differentiation of fuel type by analysis.

Question 5: Do you have NOx source test data and boiler operation, maintenance and performance reports for new boilers on line since spring of 1976? Is there any indication of tribe corrosion and wastage-however small-for how NOx operation mode?

Answer: The only recent tests for tube corrosion were at Utah Power & Light, Huntington Canyon Station and Wisconsin Power & Light, Columbia Station (EPA Projects) which indicated no evidence of increased corrosion and wastage.

On other C-E units with OFA in operation, we have had no reports of operational difficulties or corrosion on wastage problems. These units have not been specifically surveyed for problems.

Sincerely yours,

COMBUSTION ENGINEERING, INC.

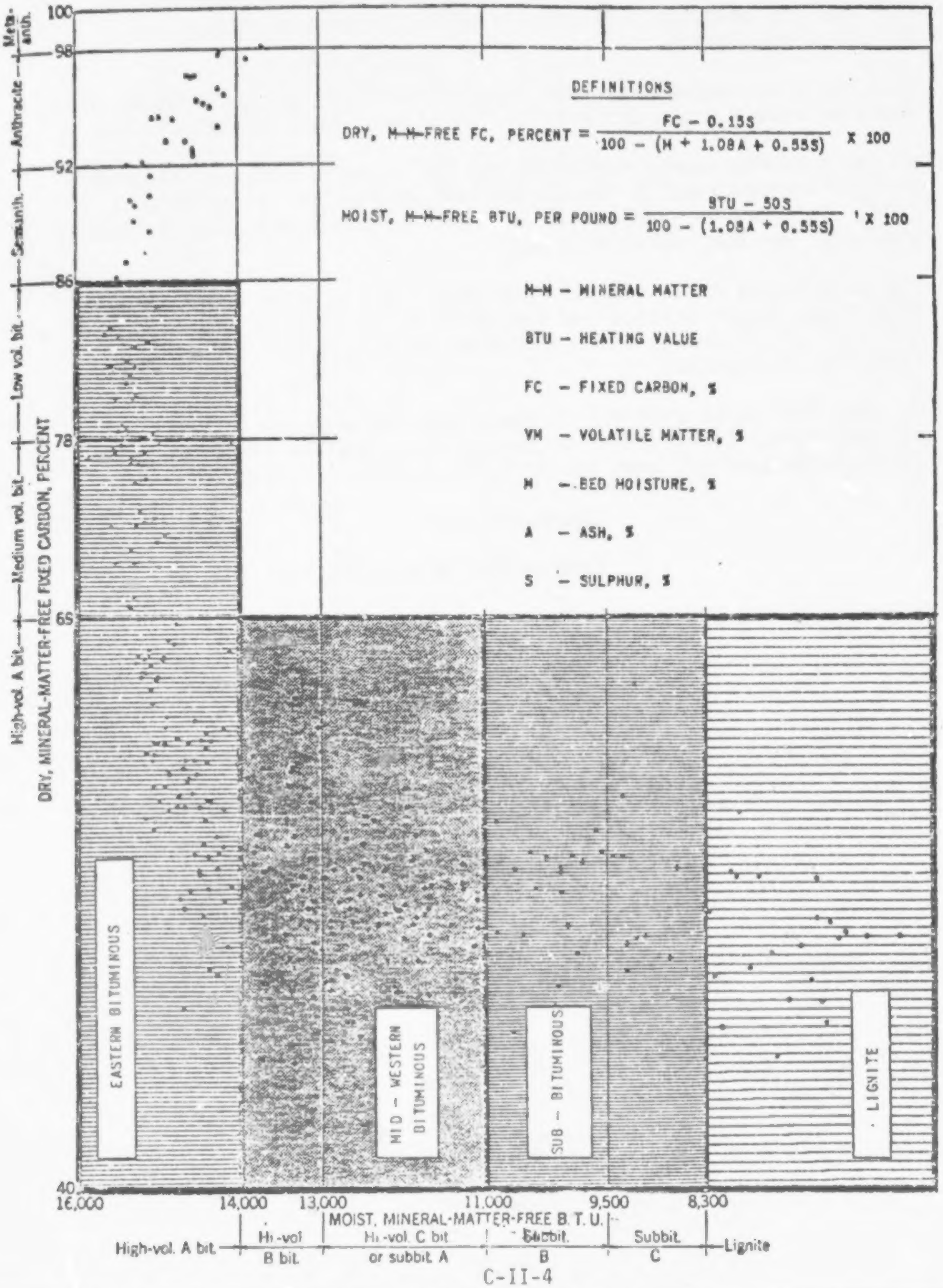
Henry E. Burbach

Henry E. Burbach
Director, Proposal Engineering

HEB:mm
attach.

COAL CLASSIFICATION

ENGINEERING DEPT. STANDARDS SHEET NO. 61-038



DEFINITIONS

$$\text{DRY, M-M-FREE FC, PERCENT} = \frac{FC - 0.15S}{100 - (M + 1.08A + 0.55S)} \times 100$$

$$\text{MOIST, M-M-FREE BTU, PER POUND} = \frac{BTU - 50S}{100 - (1.08A + 0.55S)} \times 100$$

M-M – MINERAL MATTER

BTU – HEATING VALUE

FC – FIXED CARBON, %

VM – VOLATILE MATTER, %

M – BED MOISTURE, %

A – ASH, %

S – SULPHUR, %

C-E Power Systems
Combustion Engineering, Inc.
1000 Prospect Hill Road
Windsor, Connecticut 06095

Tel. 203/688-1911
Telex: 9-9297

POWER
SYSTEMS

July 30, 1976

Mr. John O. Copeland
Industrial Studies Branch
Emission Standards & Engineering Division
United States Environmental Protection Agency
Research Triangle Park
North Carolina 27711

Dear Mr. Copeland:

The attached information has been prepared in response to your letter of June 2, 1976, for NOx emission data on C-E pulverized coal-fired steam generators. Specifically, you requested the following in addition to NOx emission levels:

a. Ultimate analysis, ash analysis, and heating value of the coal fed to the pulverizers during testing.

b. Description of combustion air adjustments during testing.

c. Boiler load during testing.

d. Concurrent data on CO, O_2, CO_2, ash combustible content, hydrocarbons, and polynuclear organic matter emissions.

e. Corrosion test results.

f. Corrollary data on test methods.

The attached Summary of Field Test Data covers items "a" thru "e" of your request. C-E field test data from 14 units, ranging in plan area from 408 sq. ft. to 2760 sq. ft. and in rating from 50 Mw to 600 Mw, is presented. The coals fired in these units are as follows:

High Sodium Lignite - Units A,B
Texas Lignite - Unit C
Western Sub "C" - Units D,E
Western Sub "B" - Units F,G
Western Bituminous - Units H,I,J
Mid-Western Bituminous - Unit K
Eastern Bituminous - Units L,M,N

An analysis by you of the data presented should lead to the following conclusions:

a. That C-E tangentially-fired boilers are capable of meeting the present EPA limit for all coal types at normal excess air levels (20-25% excess air),

b. that excess air has a predominating effect on NOx emission levels for all coal types,

c. that overfire air is extremely effective in reducing NOx emissions from tangentially-fired boilers for all coal types,

d. that for Eastern Bituminous coals, tangentially-fired boilers would be capable of meeting an 0.6 lbs. NO_2/MMBTU emission limit when equipped with overfire air,

e. that for the lower rank Western coals and lignite, tangentially-fired boilers would be capable of meeting an 0.5 lbs. NO_2/MMBTU emission limit when equipped with overfire air, and

f. that increased waterwall corrosion rates, increased CO emissions, and increased ash combustible content when operating with overfire air for NOx control is not a problem on tangentially-fired boilers.

No data is given for unburned hydrocarbon or polynuclear organic matter emissions. When measured, unburned hydrocarbons have always been less than 2 PPM on C-E coal-fired boilers. C-E has never attempted to measure emission of polynuclear organic matter.

The second attachment discusses the three NOx measurement methods employed by C-E in our field test program. A brief discussion of the various methods, including the advantages and disadvantages, as well as a comparison of actual NOx field test data obtained by the three methods, is presented.

Should you require any additional information, please feel free to contact me.

Very truly yours,

COMBUSTION ENGINEERING, INC.

H E Burbach

H. E. Burbach
Director, Proposition Engineering

:mm
attach.

Summary of Field Test Data

Unit Identification

Unit	Utility	Station	Tested
A	Ottertail Power	Hoot Lake #2	11/70
B	Saskatchewan Power Corp.	Boundary Dam #4	3/73
C	Industrial Generating Co.	Big Brown #1	5/72-8/72
D	Public Service Co. of Colorado	Comanche #1	2/74
E	Minnesota Power & Light Co.	Clay Boswell #3	4/74
F	Utah Power & Light Co.	Naughton #2	7/70-8/70
G	Utah Power & Light Co.	Naughton #3	9/72
H	Utah Power & Light Co.	Gadsby #3	5/71
I	Public Service Co. of Colorado	Cherokee #4	1/72
J	Utah Power & Light Co.	Huntington Canyon #2	5/75-9/75
K	Union Electric Co.	Labadie #1	6/71
L	Alabama Power	Barry #4	1/73
M	Cincinnati Gas & Electric	Beckjord #6	10/69
N	Tennessee Valley Authority	Widows Creek #7B	4/71

Note:

1. 'NA' in the column labled OFA Damper Setting means the unit was not equipped with overfire air.
2. * in the column labled OFA Damper Setting indicates that overfire air was simulated by operating the top elevation of nozzles on air only.
3. All damper settings are given as percent open, 0 meaning fully closed, 100 meaning fully open.
4. 'NR' means NOT RECORDED.
5. Higher heating value is given in BTU/LB, as received basis.

UNIT A:50 MW,RR BOILER FIRING HIGH SODIUM LIGNITE
THRU 4 ELEVATIONS OF TILTING TANGENTIAL
NOZZLES:PA=403 SQ.FT.

TEST	LOAD (MW)	ELEV. IN SERVICE	TILT (DEGS)	AIR PREHEAT (F)	EXCESS AIR (%)	DAMPER SETTING PRI/SEC	CFA DAMPER SETTING	% THEO. AIR TO WINDBOX	OXY %	FLUE NOX LBS/MMBTU	GAS ANALYSIS CO PPM	%C IN FLYASH	CO2 (%)
1	53	3	-24	674	27.5	100/55	NA	124.4	4.6	0.483	NR	NR	NR
2	52	3	-21	673	33.2	100/60	NA	113.8	5.3	0.490	NR	NR	NR
3	52	3	-18	683	32.5	100/60	NA	112.2	5.1	0.473	NR	NR	NR
4	39	3	12	624	31.9	100/60	NA	115.7	5.2	0.674	NR	NR	NR
5	52	3	-22	676	28.3	100/55	NA	124.4	4.7	0.487	NR	NR	NR
6	40	3	-14	667	27.5	70/25	NA	125.8	4.6	0.617	NR	NR	NR

ULTIMATE ANALYSIS % BY WEIGHT

CARBON = 43.60
HYDROGEN = 3.30
SULFUR = 1.00
NITROGEN = 0.90
OXYGEN = 12.00
ASH = 7.20
MOISTURE = 32.00

HHV, AS RECEIVED = 7305

ASH ANALYSIS, % BY WEIGHT

SILICA = 13.80
ALUMINA = 10.70
FERRIC OXIDE = 8.40
CALCIUM OXIDE = 24.20
MAGNESIA = 7.60
SODIUM OXIDE = 9.00
POTASSIUM OXIDE = 0.40
TITANIUM OXIDE = 0.40
PHOSPHORUS PENTAOXIDE = 0.60
SULFUR TRIOXIDE = 20.30

Tests 1,2,3,5: Normal Operation

Test 6: Higher than normal furnace to windbox pressure drop.

UNIT B:150 MW,RR BOILER FIRING HIGH SODIUM LIGNITE
THRU 6 ELEVATIONS OF TILTING TANGENTIAL
NOZZLES:PA=1009 SQ.FT.

TEST	LOAD (MW)	ELEV. IN SERVICE	TILT (DEGS)	AIR PREHEAT (F)	EXCESS AIR (%)	DAMPER SETTING PRI/SEC	OFA DAMPER SETTING	% THEO. AIR TO WINDBOX	OXY %	FLUE NOX LBS/MMBTU	GAS CO PPM	ANALYSIS %C IN FLYASH	CO2 (%)
1	152	6	5	520	23.1	100/50	NA	119.8	4.0	0.587	NR	0.33	19.4
2	156	6	20	530	10.6	100/50	NA	107.6	2.1	0.448	NR	0.42	19.4
3	154	5	15	513	16.4	50/50	*	99.6	3.0	0.370	NR	0.12	19.5
4	154	5	-15	510	10.0	40/40	*	94.1	2.0	0.322	NR	0.18	19.
5	149	6	20	535	15.0	100/10	NA	111.9	2.8	0.643	NR	0.58	19.
6	149	6	-5	521	15.7	100/10	NA	112.6	2.9	0.545	NR	0.32	19.4

ULTIMATE ANALYSIS % BY WEIGHT

CARBON = 38.40
HYDROGEN = 2.60
SULFUR = 0.90
NITROGEN = 0.70
OXYGEN = 11.65
ASH = 10.75
MOISTURE = 35.00

HHV, AS RECEIVED = 6415

ASH ANALYSIS, % BY WEIGHT

SILICA = 40.90
ALUMINA = 15.10
FERRIC OXIDE = 4.30
CALCIUM OXIDE = 12.95
MAGNESIA = 3.50
SODIUM OXIDE = 6.45
POTASSIUM OXIDE = 3.10
TITANIUM OXIDE = 0.85
PHOSPHORUS PENTAOXIDE = 0.30
SULFUR TRIOXIDE = 11.85

Test 1: Normal Operation
Tests 3 & 4: Simulated OFA
Test 2: Low Excess Air
Test 5-6: Changed Windbox damper settings

UNIT C:575 MW,SCRRD BOILER FIRING TEXAS LIGNITE
THRU 8 ELEVATIONS OF TILTING TANGENTIAL
NOZZLES:PA=1707 SQ.FT./CELL

TEST	LOAD (MW)	ELEV. IN SERVICE	TILT (DEGS)	AIR PREHEAT (F)	EXCESS AIR (%)	DAMPER SETTING PRI/SEC	OFA DAMPER SETTING	% THEO. AIR TO WINDBOX	OXY %	FLUE NOX LBS/MMBTU	GAS CO PPM	ANALYSIS %C IN FLYASH	CO2 (%)
6	571	8	0	783	22.4	100/35	NA	121.5	3.9	0.567	NR	NR	14.5
16	570	8	0	773	21.7	95/50	NA	120.4	3.8	0.542	NR	NR	14.5
19	570	8	0	764	21.1	95/40	NA	120.7	3.7	0.571	NR	NR	14.5
23	563	8	0	757	21.4	50/50	NA	120.1	3.8	0.472	NR	NR	14.5
25	563	7	0	761	19.0	50/50	NA	114.9	3.4	0.504	NR	NR	NR
27A	564	7	0	769	19.7	50/50	*	103.3	3.5	0.390	NR	NR	NR
30	566	7	0	757	19.7	50/50	*	105.9	3.5	0.396	NR	NR	NR
10	496	8	0	750	36.6	85/40	NA	135.5	5.7	0.672	NR	NR	12.5
12	497	8	0	753	15.8	85/15	NA	115.5	2.9	0.585	NR	NR	14.1
4	284	4	0	654	36.6	100/30	NA	130.2	5.7	0.413	NR	NR	12.5
18A	282	4	0	624	18.3	85/35	NA	112.7	3.3	0.207	NR	NR	13.9

ULTIMATE ANALYSIS % BY WEIGHT

CARBON = 41.20
HYDROGEN = 3.10
SULFUR = 0.30
NITROGEN = 0.70
OXYGEN = 12.20
ASH = 9.90
MOISTURE = 32.10

HHV, AS RECEIVED = 7250

ASH ANALYSIS, % BY WEIGHT

SILICA = 42.10
ALUMINA = 14.50
FERRIC OXIDE = 5.50
CALCIUM OXIDE = 16.20
MAGNESIA = 3.40
SODIUM OXIDE = 0.50
POTASSIUM OXIDE = 0.50
TITANIUM OXIDE = 1.10
PHOSPHORUS PENTAOXIDE = 0.10
SULFUR TRIOXIDE = 12.90

Tests 6, 16, 19: Normal Operation
Tests 10,12,4,18A: Normal Operation - Reduced Load
Tests 23, 25: Modified Air Damper Settings
Tests 27A, 30: Simulated OFA

UNIT D:350 MW,CCRR BOILER FIRING WESTERN SUB C COAL
THRU 5 ELEVATIONS OF TILTING TANGENTIAL
NOZZLES:OFA PORTS:PA=1813 SQ.FT.

TEST	LOAD (MW)	ELEV. IN SERVICE	TILT (DEGS)	AIR PREHEAT (F)	EXCESS AIR (%)	DAMPER SETTING PRI/SEC	OFA DAMPER SETTING	% THEO. AIR TO WINDBOX	OXY %	FLUE NOX LBS/MMBTU	GAS CO PPM	ANALYSIS %C IN FLYASH	CO2 (%)
11A	355	5	0	755	25.0	90/60	5	119.4	4.2	0.446	NR	NR	15.4
3B	360	5	0	745	22.0	85/55	10	114.5	3.8	0.444	NR	NR	NR
10A	360	5	0	765	18.3	90/65	10	112.4	3.2	0.412	NR	NR	16.2
8H	365	5	0	785	17.9	90/50	100	99.1	3.2	0.353	NR	NR	16.3
9C	355	5	0	745	17.6	85/45	80	98.5	3.2	0.318	NR	NR	16.3
6A	355	5	0	750	28.8	90/70	10	121.2	4.7	0.492	NR	NR	NR
5D	350	5	0	755	27.2	90/70	25	117.1	4.5	0.457	NR	NR	NR
7A	360	5	0	755	27.2	90/70	50	112.8	4.5	0.410	NR	NR	NR
7E	360	5	0	755	27.2	90/65	75	109.5	4.5	0.361	NR	NR	NR
7D	360	5	0	755	27.2	90/65	100	108.6	4.5	0.360	NR	NR	NR
13A	273	5	0	700	23.4	60/30	10	119.0	4.6	0.420	NR	NR	15.0
9G	260	5	0	685	23.8	60/30	10	114.8	4.0	0.422	NR	NR	NR
9F	260	5	0	695	26.1	60/15	80	98.2	4.4	0.281	NR	NR	NR
9H	135	3	0	620	65.6	55/10	80	91.6	8.3	0.267	NR	NR	NR

ULTIMATE ANALYSIS % BY WEIGHT

CARBON = 48.40
HYDROGEN = 3.20
SULFUR = 0.40
NITROGEN = 0.40
OXYGEN = 12.60
ASH = 4.60
MOISTURE = 30.40

HHV, AS RECEIVED = 8380

ASH ANALYSIS, % BY WEIGHT

SILICA = 27.80
ALUMINA = 14.70
FERRIC OXIDE = 4.10
CALCIUM OXIDE = 24.50
MAGNESIA = 4.90
SODIUM OXIDE = 4.50
POTASSIUM OXIDE = 2.00
TITANIUM OXIDE = 1.30
PHOSPHORUS PENTAOXIDE = 1.00
SULFUR TRIOXIDE = 14.50

Note: Low Fuel in this coal.

Tests 11A,3B,6A,5D,7A,E,D: Normal Operation - Various Pri., Sec., OFA damper settings
Tests 10A,8H,9C: Low Excess Air
Tests 13A,9G,9F,9H: Low Load Operation

UNIT E:350 MW,CCRR BOILER FIRING WESTERN SUB C COAL
THRU 5 ELEVATIONS OF TILTING TANGENTIAL
NOZZLES:PA=1833 SQ.FT.

TEST	LOAD (MW)	ELEV. IN SERVICE	TILT (DEGS)	AIR PREHEAT (F)	EXCESS AIR (%)	DAMPER SETTING PRI/SEC	OFA DAMPER SETTING	% THEO. AIR TO WINDBOX	OXY %	FLUE NOX LBS/MMBTU	GAS CO PPM	ANALYSIS %C IN FLYASH	CO2 (%)
1	340	5	0	697	33.4	100/45	NA	128.9	5.2	0.587	NR	NR	NR
5	300	5	0	676	23.3	100/30	NA	121.3	4.0	0.615	NR	NR	NR
6	317	5	0	690	41.8	100/40	NA	138.5	6.2	0.650	NR	NR	NR
7	320	5	0	661	27.9	100/25	NA	125.6	4.6	0.557	NR	NR	NR
8	304	5	30	675	23.3	100/25	NA	121.1	4.0	0.609	NR	NR	NR
9	306	5	0	694	40.5	100/40	NA	137.7	6.0	0.675	NR	NR	NR

ULTIMATE ANALYSIS % BY WEIGHT

CARBON = 47.90
HYDROGEN = 3.20
SULFUR = 1.50
NITROGEN = 0.60
OXYGEN = 12.50
ASH = 9.30
MOISTURE = 25.00

HHV, AS RECEIVED = 8345

Tests 1,5,7,8: Normal Operation
Tests 6,9: High Excess Air Operation

ASH ANALYSIS, % BY WEIGHT

SILICA = 37.60
ALUMINA = 15.30
FERRIC OXIDE = 15.10
CALCIUM OXIDE = 9.10
MAGNESIA = 3.60
SODIUM OXIDE = 0.40
POTASSIUM OXIDE = 0.90
TITANIUM OXIDE = 0.60
PHOSPHORUS PENTAOXIDE = 0.10
SULFUR TRIOXIDE = 12.50

UNIT F:225 MW,RR BOILER FIRING WESTERN SUB B COAL
THRU 4 ELEVATIONS OF TILTING TANGENTIAL
NOZZLES:PA=1406 SQ.FT.

TEST	LOAD (MW)	ELEV. IN SERVICE	TILT (DEGS)	AIR PREHEAT (F)	EXCESS AIR (%)	DAMPER SETTING PRI/SEC	OFA DAMPER SETTING	% THEO. AIR TO WINDBOX	OXY %	FLUE NOX LBS/MMBTU	GAS CO PPM	ANALYSIS %C IN FLYASH	CO2 (%)
6	217	4	0	706	30.0	55/50	NA	124.2	4.9	0.883	NR	0.8	NR
5	217	4	0	697	23.8	45/45	NA	117.3	4.1	0.744	NR	1.4	NR
2	212	4	0	682	19.0	40/40	NA	113.3	3.4	0.598	NR	1.2	NR
4	216	4	0	682	17.6	40/40	NA	111.5	3.2	0.625	NR	2.3	NR
13	216	4	0	658	9.0	35/35	NA	104.4	1.8	0.541	NR	2.0	NR
14	217	4	0	662	6.7	35/35	NA	100.6	1.4	0.516	NR	2.6	NR
7	158	3	5	600	16.4	20/25	NA	108.6	3.0	0.432	NR	0.4	NR
9	158	3	5	600	14.4	15/15	*	77.6	2.7	0.311	NR	0.5	NR

ULTIMATE ANALYSIS % BY WEIGHT

CARBON = 52.50
HYDROGEN = 3.60
SULFUR = 0.50
NITROGEN = 1.25
OXYGEN = 13.60
ASH = 5.50
MOISTURE = 23.10

HHV, AS RECEIVED = 9070

ASH ANALYSIS, % BY WEIGHT

SILICA = 63.10
ALUMINA = 11.70
FERRIC OXIDE = 8.80
CALCIUM OXIDE = 4.90
MAGNESIA = 2.20
SODIUM OXIDE = 0.10
POTASSIUM OXIDE = 1.20
TITANIUM OXIDE = 0.50
PHOSPHORUS PENTAOXIDE = 0.20
SULFUR TRIOXIDE = 6.00

Tests 6,5,2,4,13,14: Indicated Steady Reduction in Excess Air.
Tests 5,2: Approximately Normal Operation.
Tests 7,9: Reduced Load, with Simulated OFA on 9.

UNIT G:300 MW,CCRR BOILER FIRING WESTERN SUB B
COAL THRU 5 ELEVATIONS OF TILTING
TANGENTIAL NOZZLES,PA=1813 SQ.FT.

TEST	LOAD (MW)	ELEV. IN SERVICE	TILT (DEGS)	AIR PREHEAT (F)	EXCESS AIR (%)	DAMPER SETTING PRI/SEC	OFA DAMPER SETTING	% THEO. AIR TO WINDBOX	OXY %	FLUE GAS ANALYSIS NOX LBS/MMBTU	CO PPM	%C IN FLYASH	CO2 (%)
18	328	5	0	672	22.0	85/40	NA	120.6	3.8	0.686	30	NR	14.7
19	325	5	0	667	11.0	90/30	NA	109.9	2.2	0.558	225	NR	15.8
20	310	4	0	660	14.7	95/40	*	88.0	2.7	0.325	45	NR	14.5
21	310	4	0	653	12.3	50/20	*	76.6	2.3	0.266	500	NR	14.8
1	256	5	0	619	28.8	70/30	NA	126.9	4.7	0.738	30	NR	12.9
2	260	4	0	623	29.6	90/35	*	98.9	4.8	0.420	15	NR	13.5
10	256	4	0	615	16.7	20/55	*	88.6	3.0	0.269	375	NR	16.8
14	199	4	0	574	25.0	65/30	NA	118.4	4.2	0.614	20	NR	14.6
15	198	3	0	573	25.0	70/35	*	77.9	4.2	0.230	25	NR	13.4

ULTIMATE ANALYSIS % BY WEIGHT

CARBON = 53.33
HYDROGEN = 3.74
SULFUR = 0.40
NITROGEN = 1.18
OXYGEN = 12.60
ASH = 5.20
MOISTURE = 23.55

HHV, AS RECEIVED = 9150

ASH ANALYSIS, % BY WEIGHT

SILICA = 66.20
ALUMINA = 13.90
FERRIC OXIDE = 7.70
CALCIUM OXIDE = 4.70
MAGNESIA = 2.10
SODIUM OXIDE = 0.10
POTASSIUM OXIDE = 1.30
TITANIUM OXIDE = 0.50
PHOSPHORUS PENTAOXIDE = 0.20
SULFUR TRIOXIDE = 0.20

Test 18: Normal Operation
Tests 19,20,21: Reduced Excess Air. Simulated OFA on 20 and 21.
Test 1-2: Reduced Load. High Excess Air, Simulated OFA on 2.
Test 10: Reduced Load, Low Excess Air, Simulated OFA.
Tests 14,15: Reduced Load, Normal Excess air. Simulated OFA on 15.

UNIT H:100 MW,RR BOILER FIRING WESTERN BIT. COAL
THRU 4 ELEVATIONS OF TILTING TANGENTIAL
NOZZLES:PA=877 SQ.FT.

TEST	LOAD (MW)	ELEV. IN SERVICE	TILT (DEGS)	AIR PREHEAT (F)	EXCESS AIR (%)	DAMPER SETTING PRI/SEC	OFA DAMPER SETTING	% THEO. AIR TO WINDBOX	OXY %	FLUE NOX LBS/MMBTU	GAS CO PPM	ANALYSIS %C IN FLYASH	CO2 (%)
9	100	4	0	570	23.1	100/25	NA	119.6	4.0	0.678	NR	2.5	NR
8A	99	4	0	583	16.4	100/25	NA	113.0	3.0	0.561	NR	NR	NR
8	99	4	0	583	13.3	100/25	NA	109.7	2.5	0.469	NR	6.8	NR
7	99	4	0	588	7.6	100/25	NA	104.3	1.5	0.352	NR	7.3	NR
1	72	3	0	540	16.4	75/50	NA	114.7	3.0	0.400	NR	8.5	NR
13	82	3	0	578	17.6	100/25	*	86.6	3.2	0.260	NR	7.5	NR
17	81	3	0	577	17.0	100/25	*	86.2	3.1	0.218	NR	9.2	NR

ULTIMATE ANALYSIS % BY WEIGHT

CARBON = 68.00
HYDROGEN = 5.25
SULFUR = 0.45
NITROGEN = 1.30
OXYGEN = 9.20
ASH = 7.30
MOISTURE = 8.50

HHV, AS RECEIVED = 12280

ASH ANALYSIS, % BY WEIGHT

SILICA = 52.10
ALUMINA = 14.60
FERRIC OXIDE = 6.50
CALCIUM OXIDE = 14.50
MAGNESIA = 2.10
SODIUM OXIDE = 5.70
POTASSIUM OXIDE = 0.60
TITANIUM OXIDE = 0.70
PHOSPHORUS PENTAOXIDE = 0.20
SULFUR TRIOXIDE = 0.50

Test 9: Normal Operation
Test 8A,8,7: Reduced Excess Air
Tests 1,13,17: Reduced Load, Reduced Excess Air, Simulated OFA on 13,17.

NOTE: UNIT H IS EQUIPPED WITH GAS RECIRCULATION THRU THE HOPPER BOTTOM.

UNIT I:350 MW,CCRR BOILER FIRING WESTERN BIT COAL
THRU 5 ELEVATIONS OF TILTING TANGENTIAL
NOZZLES:PA=1813 SQ.FT.

TEST	LOAD (MW)	ELEV. IN SERVICE	TILT (DEGS)	AIR PREHEAT (F)	EXCESS AIR (%)	DAMPER SETTING PRI/SEC	OFA DAMPER SETTING	% THEO. AIR TO WINDBOX	OXY %	FLUE NOX LBS/MMBTU	GAS CO PPM	ANALYSIS %C IN FLYASH	CO2 (%)
6	370	5	0	562	38.5	100/55	NA	133.6	5.9	0.869	NR	NR	NR
7	368	5	0	550	37.7	50/55	NA	132.7	5.8	0.821	NR	NR	NR
8	368	5	0	570	39.3	30/100	NA	134.0	6.0	0.791	NR	NR	NR
4	370	5	0	565	29.0	80/80	NA	124.4	4.8	0.641	NR	NR	NR
10	372	5	0	587	23.7	50/60	NA	119.6	4.1	0.641	NR	NR	NR
12	183	4	-5	328	30.6	55/20	NA	114.7	5.0	0.632	NR	NR	NR

ULTIMATE ANALYSIS % BY WEIGHT

CARBON = 63.00
HYDROGEN = 4.40
SULFUR = 0.50
NITROGEN = 1.70
OXYGEN = 11.00
ASH = 8.70
MOISTURE = 10.70

HHV, AS RECEIVED = 11070

ASH ANALYSIS, % BY WEIGHT

SILICA = 54.10
ALUMINA = 28.30
FERRIC OXIDE = 3.00
CALCIUM OXIDE = 5.00
MAGNESIA = 1.50
SODIUM OXIDE = 0.60
POTASSIUM OXIDE = 1.00
TITANIUM OXIDE = 0.70
PHOSPHORUS PENTAOXIDE = 1.10
SULFUR TRIOXIDE = 1.80

Note: High Fuel N This Coal.

Test 6,7,8: High Excess Air, Modified Air Damper Settings.
Test 4: Normal Operation.
Test 10: Normal Operation, Reduced Excess Air.
Test 12: Low Load Operation.

UNIT J:400 MW,CORR BOILER FIRING WESTERN BIT COAL
THRU 5 ELEVATIONS OF TILTING TANGENTIAL
NOZZLES:OFA PORTS:PA=2290 SQ.FT.

TEST	LOAD (MW)	ELEV. IN SERVICE	TILT (DEGS)	AIR PREHEAT (F)	EXCESS AIR (%)	DAMPER SETTING PRI/SEC	OFA DAMPER SETTING	% THEO. AIR TO WINDBOX	OXY %	FLUE NOX LBS/MMBTU	GAS CO PPM	ANALYSIS %C IN FLYASH	CO2 (%)
3	428	5	15	520	40.9	100/45	0	137.8	6.2	0.845	27	2.0	12.8
15	433	5	0	510	35.5	100/50	0	135.5	5.6	0.753	27	1.3	13.3
8	430	5	8	520	19.5	100/35	0	117.5	3.5	0.627	22	6.7	15.1
14	433	5	6	515	20.2	100/45	0	118.1	3.6	0.604	24	4.4	15.0
13	433	5	3	500	15.0	100/40	0	113.1	2.8	0.508	35	4.5	15.7
A7	429	5	10	535	18.9	100/10	50	102.7	3.4	0.573	93	4.5	15.4
A8	428	5	10	535	18.9	100/10	100	96.5	3.4	0.522	160	4.0	15.3
A5	431	5	-12	535	25.2	100/20	100	105.3	4.3	0.491	15	2.0	14.6
A17	424	5	0	535	23.0	100/10	100	99.4	4.0	0.442	16	1.7	14.9
12	259	4	3	475	49.9	100/ 0	0	148.7	7.1	0.765	17	1.5	12.0
11	256	4	6	475	26.0	100/ 0	0	125.7	4.5	0.555	15	1.5	14.3
17	258	4	12	475	25.1	100/ 0	0	124.2	4.3	0.515	15	1.8	14.4

ULTIMATE ANALYSIS % BY WEIGHT

CARBON = 67.20
HYDROGEN = 4.90
SULFUR = 0.40
NITROGEN = 1.20
OXYGEN = 10.00
ASH = 8.50
MOISTURE = 7.80

HHV, AS RECEIVED = 12080

ASH ANALYSIS, % BY WEIGHT

SILICA = 54.00
ALUMINA = 16.50
FERRIC OXIDE = 4.50
CALCIUM OXIDE = 8.50
MAGNESIA = 2.00
SODIUM OXIDE = 2.50
POTASSIUM OXIDE = 1.00
TITANIUM OXIDE = 1.00
PHOSPHORUS PENTAOXIDE = 0.10
SULFUR TRIOXIDE = 5.50

Tests 3,15,8,14,13: Normal Operation, OFA Closed, Various Excess Air.
Tests A7,A8,A5,A17: Normal Operation with Various OFA Settings.
Tests 12,11,17: Reduced Load, OFA Closed, Various Excess Air

UNIT K:600 MW,CCRR BOILER FIRING MID-WEST BIT COAL
THRU 6 ELEVATIONS OF TILTING TANGENTIAL
NOZZLES:PA=2760 SQ.FT.

TEST	LOAD (MW)	ELEV. IN SERVICE	TILT (DEGS)	AIR PREHEAT (F)	EXCESS AIR (%)	DAMPER SETTING PRI/SEC	OFA DAMPER SETTING	% THEO. AIR TO WINDBOX	OXY %	FLUE GAS ANALYSIS NOX LBS/MMBTU	CO PPM	%C IN FLYASH	CO2 (%)
10	512	6	0	590	41.3	45/55	NA	136.2	6.2	0.758	NR	NR	NR
7	515	6	0	600	23.8	55/45	NA	120.3	4.1	0.703	NR	NR	NR
2	560	6	-5	610	22.4	65/45	NA	118.4	3.9	0.636	NR	NR	NR
5	571	6	0	600	21.7	55/50	NA	118.0	3.8	0.686	NR	NR	NR
4	390	6	0	545	24.7	35/20	NA	121.9	4.2	0.692	NR	NR	NR
8	388	4	0	542	21.7	55/45	NA	111.0	3.8	0.487	NR	NR	NR
9	390	4	0	538	24.7	55/35	*	99.1	4.2	0.398	NR	NR	NR

ULTIMATE ANALYSIS % BY WEIGHT

CARBON = 62.10
HYDROGEN = 4.50
SULFUR = 2.70
NITROGEN = 1.40
OXYGEN = 8.80
ASH = 10.30
MOISTURE = 10.00

HHV, AS RECEIVED = 11080

ASH ANALYSIS, % BY WEIGHT

SILICA = 47.00
ALUMINA = 18.40
FERRIC OXIDE = 16.70
CALCIUM OXIDE = 6.30
MAGNESIA = 1.20
SODIUM OXIDE = 0.50
POTASSIUM OXIDE = 2.00
TITANIUM OXIDE = 0.80
PHOSPHORUS PENTAOXIDE = 0.10
SULFUR TRIOXIDE = 5.60

Test 10: High Excess Air.
Tests 7,2,5: Normal Operation.
Tests 4,8: Reduced Load Normal Operation.
Test 9: Reduced Load, Simulated OFA.

UNIT L:370 MW,CCRR BOILER FIRING EASTERN BIT
COAL THRU 5 ELEVATIONS OF TILTING
TANGENTIAL NOZZLES,PA=1813 SQ.FT.

TEST	LOAD (MW)	ELEV. IN SERVICE	TILT (DEGS)	AIR PREHEAT (F)	EXCESS AIR (%)	DAMPER SETTING PRI/SEC	OFA DAMPER SETTING	% THEO. AIR TO WINDBOX	OXY %	FLUE NOX LBS/MMBTU	GAS CO PPM	ANALYSIS %C IN FLYASH	CO2 (%)
1	348	5	0	525	14.9	50/95	NA	111.4	2.8	0.576	30	NR	NR
35	360	5	0	520	12.2	100/50	NA	109.5	2.4	0.566	180	NR	NR
2	348	5	0	520	12.8	50/95	NA	109.4	2.4	0.552	120	NR	NR
37	348	5	0	525	12.5	20/95	NA	109.1	2.4	0.610	60	NR	NR
29	328	5	0	525	7.2	50/95	NA	103.9	1.5	0.466	85	NR	NR
32	286	4	0	495	22.4	100/50	*	103.3	4.0	0.391	55	NR	NR
9	322	4	0	508	15.1	100/50	*	95.8	2.8	0.408	115	NR	NR
8	294	4	-20	490	5.7	100/50	*	88.2	1.2	0.358	100	NR	NR

ULTIMATE ANALYSIS % BY WEIGHT

CARBON = 65.00
HYDROGEN = 4.35
SULFUR = 2.20
NITROGEN = 1.40
OXYGEN = 6.20
ASH = 12.75
MOISTURE = 8.10

HHV, AS RECEIVED = 11720

ASH ANALYSIS, % BY WEIGHT

SILICA = 45.60
ALUMINA = 24.00
FERRIC OXIDE = 19.00
CALCIUM OXIDE = 2.60
MAGNESIA = 1.00
SODIUM OXIDE = 0.30
POTASSIUM OXIDE = 2.10
TITANIUM OXIDE = 1.10
PHOSPHORUS PENTAOXIDE = 0.40
SULFUR TRIOXIDE = 3.30

Tests 1,35,2,37,29: Reduced Excess Air
Tests 32,9,8: Simulate OFA,Various Excess Air

UNIT M:400 MW,CORRP BOILER FIRING EASTERN BIT.
COAL THRU 5 ELEVATIONS OF TILTING
TANGENTIAL NOZZLES,PA=2020 SQ.FT.

TEST	LOAD (MW)	ELEV. IN SERVICE	TILT (DEGS)	AIR PREHEAT (F)	EXCESS AIR (%)	DAMPER SETTING PRI/SEC	OFA DAMPER SETTING	% THEO. AIR TO WINDBOX	OXY %	FLUE NOX LBS/MMBTU	GAS CO PPM	ANALYSIS %C IN FLYASH	CO2 (%)
2	411	5	0	575	21.0	45/45	NA	116.8	3.7	0.675	NR	NR	15.1
3	419	5	15	580	22.5	45/45	NA	118.1	3.9	0.594	NR	NR	15.0
4	251	4	20	513	20.3	45/20	NA	109.5	3.6	0.376	NR	NR	15.0
5	426	5	20	584	21.0	80/40	NA	116.8	3.7	0.669	NR	NR	14.8
6	250	4	0	504	18.3	45/20	NA	110.7	3.3	0.429	NR	NR	15.7
7	420	5	0	581	21.0	70/50	NA	118.6	3.7	0.726	NR	NR	15.1
7A	420	5	0	581	21.0	70/25	NA	118.6	3.7	0.750	NR	NR	15.1
8	412	5	-10	579	21.7	70/50	NA	119.3	3.8	0.712	NR	NR	15.2
9	255	3	0	503	19.0	30/20	NA	107.1	3.4	0.318	NR	NR	15.2

ULTIMATE ANALYSIS % BY WEIGHT

CARBON = 64.60
HYDROGEN = 4.70
SULFUR = 2.30
NITROGEN = 1.50
OXYGEN = 6.00
ASH = 12.40
MOISTURE = 8.50

HHV, AS RECEIVED = 11530

ASH ANALYSIS, % BY WEIGHT

SILICA = 47.50
ALUMINA = 22.00
FERRIC OXIDE = 17.20
CALCIUM OXIDE = 2.50
MAGNESIA = 0.90
SODIUM OXIDE = 0.40
POTASSIUM OXIDE = 2.00
TITANIUM OXIDE = 1.00
PHOSPHORUS PENTAOXIDE = 0.20
SULFUR TRIOXIDE = 2.50

Note Fuel N.

Tests 2,3,5: Normal Operation
Tests 4,6: Normal Operation, Reduced Load
Tests 7,7A,8: Modified Air Damper Settings
Test 9: Modified Air Damper Settings, Reduced Load

UNIT N:500 MW,CCRRT BOILER FIRING EASTERN BIT COAL
THRU 4 ELEVATIONS OF TILTING TANGENTIAL
NOZZLES:'B' FURNACE:PA=1613 SQ.FT.
Note: Each Furnace Cell Rated at 250 MW

TEST	LOAD (MW)	ELEV. IN SERVICE	TILT (DEGS)	AIR PREHEAT (F)	EXCESS AIR (%)	DAMPER SETTING PRI/SEC	OFA DAMPER SETTING	% THEO. AIR TO WINDBOX	OXY %	FLUE NOX LBS/MMBTU	GAS CO PPM	ANALYSIS %C IN FLYASH	CO2 (%)
11	246	5	0	525	20.1	40/65	NA	115.4	3.6	0.526	NR	1.1	NR
5	243	5	0	531	18.6	100/55	NA	115.6	3.4	0.502	30	0.8	NR
19	216	5	0	522	13.6	40/45	NA	109.5	2.6	0.469	45	1.9	NR
15	226	5	0	519	11.4	100/35	NA	109.5	2.2	0.533	20	2.3	NR
9	232	4	0	517	22.6	100/40	*	98.6	4.0	0.341	45	2.0	NR
17	226	4	0	512	20.1	20/60	*	98.8	3.6	0.325	50	2.0	NR
3	236	4	0	522	15.7	40/45	*	94.2	2.9	0.345	30	2.3	NR
13	219	4	0	514	13.3	100/25	*	87.8	2.5	0.261	45	1.5	NR
30	150	3	0	460	10.1	40/40	NA	108.9	2.0	0.344	NR	9.0	NR
31	158	3	10	475	11.9	40/40	*	91.9	2.3	0.265	NR	3.0	NR

ULTIMATE ANALYSIS % BY WEIGHT

CARBON = 58.40
HYDROGEN = 4.10
SULFUR = 3.80
NITROGEN = 1.35
OXYGEN = 7.05
ASH = 17.30
MOISTURE = 8.00

HHV, AS RECEIVED = 10660

ASH ANALYSIS, % BY WEIGHT

SILICA = 0.0
ALUMINA = 0.0
FERRIC OXIDE = 0.0
CALCIUM OXIDE = 0.0
MAGNESIA = 0.0
SODIUM OXIDE = 0.0
POTASSIUM OXIDE = 0.0
TITANIUM OXIDE = 0.0
PHOSPHORUS PENTAOXIDE = 0.0
SULFUR TRIOXIDE = 0.0

Tests 11,5: Normal Operation
Test 19,15: Reduced Excess Air
Tests 9,17,3,13: Simulated OFA, Various Excess Air
Tests 30,31: Reduced Load, Low Excess Air, Simulated OFA Test 31

NOx Measurement Techniques

Combustion Engineering's Field Testing Department currently employs three methods for determining NOx emission levels from coal-fired steam generators. These are the Phenol-Disulfonic Acid Method (ASTM 1608-60), the Whittaker Dynascience Electrochemical NOx Analyzer, and the Scott Chemiluminescence NOx Analyzer. The advantages and disadvantages of each method are noted in Table 1. These methods compare favorably with each from a standpoint of accuracy as shown in Figure 1 which is based on actual test data obtained on a coal-fired steam generator.

The Phenol-Disulfonic method was adopted in 1969 when C-E's NOx field test program was initiated. In this method, a gas sample is admitted to an evacuated flask containing an oxidizing absorbent consisting of hydrogen peroxide in dilute sulfuric acid. The nitrogen oxides in the gas (both NO and NO_2) are converted to nitric acid by the absorbing solution and the resulting nitrate ion reacted with phenol-disulphonic acid to produce a yellow solution which is measured calorimetrically against calibration curves prepared from samples of known nitrate content. This method is known to be accurate to 5 percent and is repeatable. A major disadvantage is that this method is time consuming and not suitable for optimization tests where immediate results and continuous monitoring are desirable. The Phenol-Disulfonic Acid Method is employed by C-E whenever EPA NOx compliance testing is being performed and also to verify the NOx content of bottled gases used to calibrate the Whittaker and Scott instruments. The method is not used extensively in C-E's on-going field test program because of the lengthy analysis period required.

Waterwall Corrosion Testing

The effect of biased firing and overfire air operation on waterwall corrosion potential was evaluated during three thirty (30) day baseline, biased firing and overfire air corrosion coupon tests conducted at the Alabama Power Co., Barry Station #2 generator under EPA contract #68-02-1367. The results of said testing are reported in detail in EPA-650/2-73-005, entitled "Program for Reduction of NOx from Tangential Coal-Fired Boilers--Phase II", dated June 1975. Briefly, the results of these corrosion tests indicated that the weight loss experienced by the test coupons during the thirty day test periods were within the range to be expected from the normal oxidation of carbon steel. That is, the results did not show any significant increase in waterwall corrosion during biased firing or overfire air operation for NOx control.

Additional waterwall corrosion testing, performed by C-E under EPA contract, has recently been completed at Utah Power and Light, Huntington Canyon #2. The preliminary results again indicated no significant change in waterwall corrosion when operating in the low NOx modes. Further information should be available from the EPA Project Officer, Mr. David G. Lachapelle.

Waterwall corrosion testing is to be carried on at Wisconsin Power and Light, Columbia #2, under EPA contract later this year. No other waterwall corrosion testing has been performed by C-E.

In late 1969, C-E began using the continuous recording Whittaker Dynascience Electrochemical NOx Analyzer when taking NOx measurements in the field. This instrument is an electrochemical transducer in which the gas sample passes through a membrane, dissolves in a thin layer of electrolyte, diffuses to a sensing electrode where electrons are released with the current flow being proportional to the NO partial pressure. The instrument has been found satisfactory in accuracy and response when proper precautions are taken to ensure that SO_2 and So_3 are scrubbed out of the gas sample and that the sensing cell is maintained at constant temperature. The instrument requires calibration with a gas mixture of known NO content. The Whittaker Dynascience Electrochemical NOx Analyzer is currently employed by C-E in short duration field test programs.

In 1973, C-E received delivery of a Gaseous Emission Test System developed by C-E's Field Test Department, in conjunction with Scott Laboratories, for performing environmental testing in the field. The system will continuously monitor and record NOx, O_2, CO and hydrocarbons present in the flue gas. The system is contained in an air conditioned, self-propelled, mobile emission van. The system is equipped with a Scott Chemiluminescence NOx analyzer. This instrument monitors the infra-red radiation which is emitted when the gas stream containing NO is mixed with ozone in a reaction chamber. An NO_2 to NO converter is incorporated in the chemiluminescence analyzer so that the small amount of NO_2 present in the flue gas will also be measured. The chemiluminescence analyzer can provide an extremely stable, accurate, and fast response method of measuring NOx in combustion gases if the gas sample is dried prior to measurement and a constant cell temperature is maintained. The instrument requires calibration with a gas mixture of known NO content. C-E employs the Scott Chemiluminescence NOx Analyzer in all longer duration field test programs.

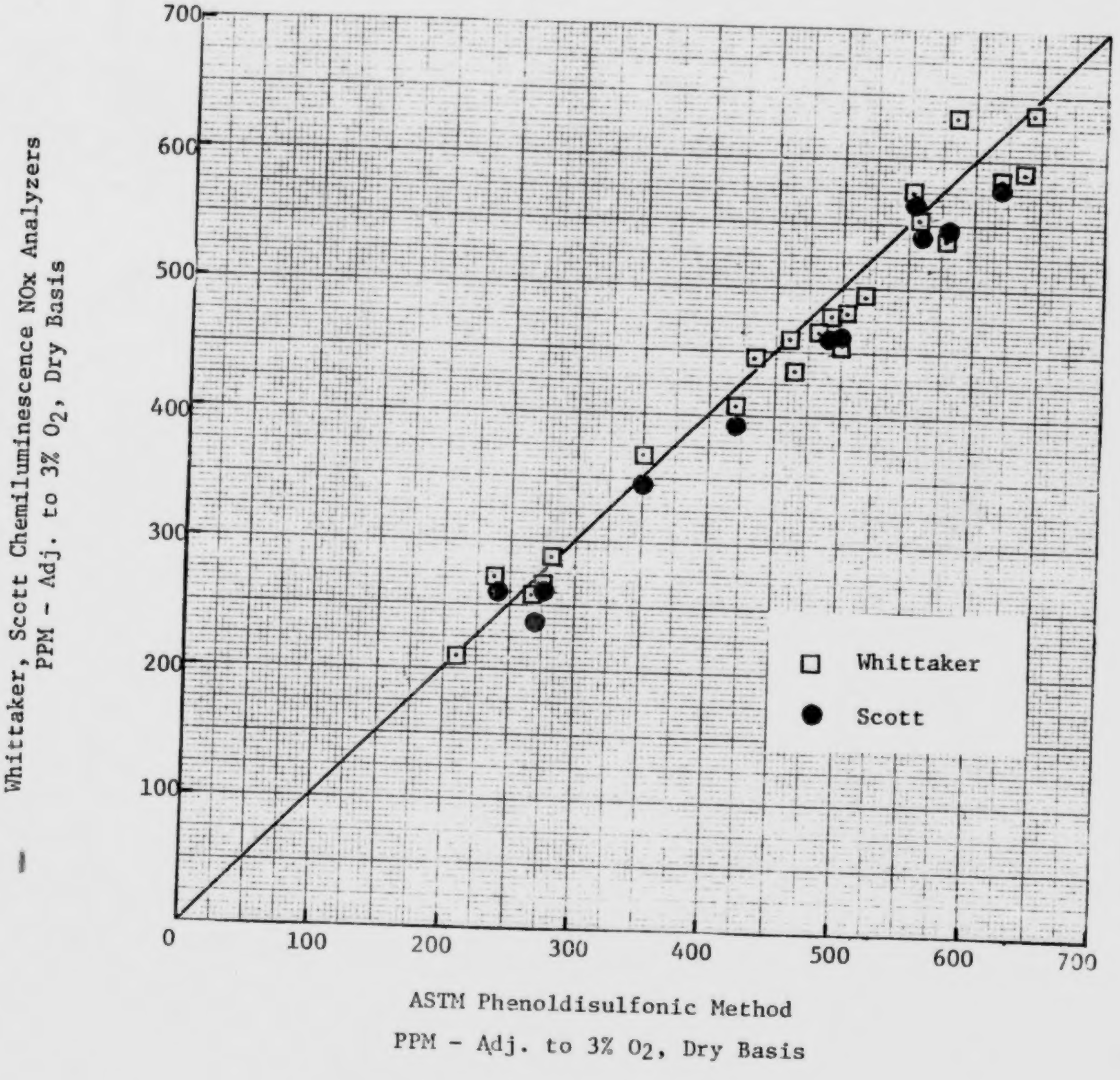
Table 1

NO_X MEASUREMENT EQUIPMENT UTILIZED BY C-E TEST GROUP

Advantages	Disadvantages
PHENOL-DISULFONIC ACID METHOD - NO_X	
1. Accuracy - 1% of the Mean	1. Grab Samples
2. Calibration Gases Not Required	2. 24 Hour Waiting Period Before Analysis
	3. Lengthy Analysis
	4. Laboratory Analysis Equipment Required
DYNASCIENCES GAS ANALYZER (ELECTROCHEMICAL) - NO_X	
1. Accuracy - 1% of Full Scale	1. SO_2 Gas Scrubber Required
2. Continuous Recording	2. Steady Ambient Temperature Required
3. Immediate Results	3. Limited Cell Life
	4. Calibration Gases Required
SCOTT GAS ANALYZER (CHEMILUMINESCENCE) - NO AND NO_2	
1. Accuracy - 1% of Full Scale	1. Steady Ambient Temperature Required
2. Continuous Recording	2. Dry Sample Required
3. Analyzes Both NO and NO_2	3. Calibration Gases Required
4. Immediate Results	

Figure 1

Comparison of NOx Measurement Techniques
ASTM Method Vs. Whittaker & Scott Analyzers



APPENDIX D

EMISSION MEASUREMENT AND CONTINUOUS MONITORING

APPENDIX D. EMISSION MEASUREMENT AND CONTINUOUS MONITORING

D.1 EMISSION MEASUREMENT METHODS

The data gathered to support the oxides of nitrogen standard for fossil fuel-fired steam generators were taken from research and development studies conducted by Exxon Research for EPA under contract (EPA Contract 68-02-1415 and EPA Report 650/2-73-005a). As described in these reports, a chemiluminescent instrument with a thermal reactor to measure both nitric oxide and nitrogen dioxide and a nondispersive infrared (NDIR) analyzer for nitric oxide and nondispersive ultraviolet (NDUV) for nitrogen dioxide were used. Oxygen was also measured so that the oxides of nitorgen emissions could be corrected to 3 percent oxygen.

The contractor reports included insufficient details on the test data and sampling techniques (instrument zero and calibration responses and sampling probe locations) to enable an evaluation of the quantitative accuracy of the measurements. However, from statements written in the reports, it was concluded that the contractor followed all the necessary procedures to ensure valid measurements, i.e., daily calibration, recalibration when zero drift was appreciable, well maintained instruments, certified calibration gases, and a multipoint sample system to remove any gas concentration stratification.

D.2 CONTINUOUS MONITORING

EPA has established monitoring performance specifications in Appendix B of 40 CFR Part 60. The specifications were developed for large industrial sources, including power plants. Continuous monitoring data are available to demonstrate the applicability of monitors to measure and record oxides of nitrogen and oxygen or carbon dioxide.

The decrease in the level of the oxides of nitrogen standard will not affect the feasibility of continuous monitoring at power plants. Oxygen or carbon dioxide can also be measured to convert the concentration data into units of the standard (nanograms per Joule).

The costs of gaseous pollutant monitors for oxides of nitrogen and oxygen or carbon dioxide have been estimated in the range of $30,000 capital, $5,000 installation, $3,000 to $7,000 performance tests, and $16,000 annual operating. Facilities which have need for more than one monitor could reduce their total cost by selecting an extractive type system and by time sharing the system between several locations.

D.3 PERFORMANCE TEST METHODS

A continuous monitoring system that meets Performance Specification #2 for oxides of nitrogen and Performance Specification #3 for oxygen or carbon dioxide which are set forth in 40 CFR 60 Appendix B, is recommended as the performance test method. In addition to the performance specifications, the zero and calibration span drift of the monitors is recommended to be checked at least once per 24-hour period of performance averaging time. These checks should be made in accordance with 40 CFR 60.13 (Subpart A - General Provisions, Monitoring Requirements). The monitoring data are recommended to be expressed in terms of the proposed standard (nanograms/Joule heat input) by using the calculation procedures specified in proposed EPA Method 19, "Determination of Sulfur Removal Efficiency of Fuel Pretreatment and Sulfur Dioxide Control Systems and Determination of Particulate, Sulfur Dioxide, and Nitrogen Oxides Emission Rates from Fossil Fuel-Fired Steam Generators."

APPENDIX E

ENFORCEMENT ASPECTS

E.1 GENERAL

The candidate affected facilities discussed in this document are limited to electric utility (other than lignite) fired steam generators of more than 73 megawatts (250 x 10^6 Btu) gross heat input.

As discussed in Chapter 5, some changes in steam generators can cause existing sources to become subject to new source performance standards for modified or reconstructed sources.

The rules and regulations for determining if a source will be subject to new source performance standards by reason that the source is new, modified, or reconstructed, are given in Subpart A, Part 60, Subchapter C, Chapter 1, Title 40, Code of Federal Regulations. In view of the multi-million dollar capital costs of large steam generators, it is suggested that interpretation of the foregoing rules and regulations be reviewed through the U. S. Environmental Protection Agency Regional Office Enforcement Division for the region where a source will be located.

The locations and addresses of these regional offices are as follows:

Region I - Connecticut, Maine, Massachusetts, New Hampshire
Rhode Island, Vermont

John F. Kennedy Federal Building
Boston, MA 02203
Telephone: 617-223-7210

Region II - New Jersey, New York, Puerto Rico, Virgin Islands

26 Federal Plaza
New York, NY 10007
Telephone: 212-264-2525

Region III - Delaware, District of Columbia, Maryland,
Pennsylvania, Virginia, West Virginia

Curtis Building
6th and Walnut Streets
Philadelphia, PA 19106
Telephone: 215-597-9814

Region IV - Alabama, Florida, Georgia, Mississippi,
Kentucky, North Carolina, South Carolina,
West Virginia

345 Courtland, N.E.
Atlanta, GA 30308
Telephone: 404-881-4727

Region V - Illinois, Indiana, Michigan, Minnesota,
Ohio, Wisconsin

230 South Dearborn
Chicago, IL 60604
Telephone: 312-353-2000

Region VI - Arkansas, Louisiana, New Mexico, Oklahoma, Texas

First International Building
1201 Elm Street
Dallas, Texas 75270
Telephone: 214-767-2000

Region VII - Iowa, Kansas, Missouri, Nebraska

1735 Baltimore Street
Kansas City, MO 64108
Telephone: 816-374-5493

Region VIII - Colorado, Montana, North Dakota,
South Dakota, Utah, Wyoming

1860 Lincoln Street
Denver, CO 80295
Telephone: 303-837-3895

Region IX - Arizona, California, Hawaii, Nevada, Guam,
American Samoa

215 Fremont Street
San Francisco, CA 94051
Telephone: 415-556-2320

Region X - Washington, Oregon, Idaho, Alaska

1200 Sixth Avenue
Seattle, WA 98101
Telephone: 206-442-1220

E.3 COMPLIANCE

General procedures for compliance testing and emission monitoring are specified in Subpart A, Part 60, Subchapter C, Chapter 1, Title 40, Code of Federal Regulations. Special regulations for compliance testing and emisssion monitoring for NO_x emissions from electric utility steam generators will be specified in Subpart D(a), Part 60, Title 40, Code of Federal Regulations. In summary, these regulations would require that new sources be tested for compliance after shakedown and that sources be equipped for NO_x continuous compliance monitoring. These emission monitoring systems must be field tested for accuracy.

Continuous emission monitoring is the most important method for determining if a source is in compliance with NO_x new source performance standards for pulverized coal-fired steam generators. As discussed in Chapter 6, NO_x emissions from modern low NO_x emission design steam generators can vary widely depending on the way the unit is operated. Consequently, unless NO_x emissions are monitored at all times, a source tested for compliance after shakedown might be subsequently operated with NO_x emission levels substantially exceeding the regulatory limit, thereby circumventing the purpose of the emission limitation.

APPENDIX F

BASIS FOR DISPERSION ESTIMATES

F.1 GENERAL

An analysis was made to assess the ambient concentrations of pollutants which would result from NO_x emissions from pulverized coal combustion. For the purpose of the study, it was assumed NO_x pollutants behave as non-reactive gases.

F.2 PLANT CHARACTERISTICS

Table F-1 gives information on the plants studied.[1] All plants were pulverized coal-fired steam generators controlled to meet an NO_x limit of 300 nanograms per joule (0.7 $lb/10^6$ Btu).

Heat rate was assumed to be 10.56 megajoules (10,000 Btu) per kilowatt hour generated from combustion. Plants equipped with 75, 175, 275 metre (246, 574, and 902 ft) stacks were studied. Estimated heights of tall structures near the stacks are given in Table F.1.

It was assumed that plants would operate at all times during a year at full load capacity.

F.3 MODEL TECHNIQUES

A summary description of the models is given in Sections F.5 and F.6.

The model was programmed to derive a set of dispersion conditions for the basic meteorological data for each hour of the given year. The calculations simulated the interaction between the plant characteristics and these dispersion conditions to produce a dispersion pattern for each hour. These computations were performed for each point in an array of 180 receptors encircling the plant and extending downwind from the site. Values were calculated at each of the receptors for each hour and were integrated and averaged to calculate a mean annual average.

TABLE F-1[1]

EMISSION SOURCE CHARACTERISTICS OF THE PROTOTYPE PULVERIZED COAL COMBUSTION PLANTS

Production Rates	Case No.	No. of Stacks	Emission Rates (gm/sec)		Stack Height (metres)	Stack Temp. (°K)	Stack Velocity (m/sec)	Stack Diam. (metres)	Control Building Height (metres)
			NO	NO_2					
25 MW	1	1	14.2	0.2	75	400	20	1.68	15
	2	1	14.2	0.2	175	400	20	1.68	15
	3	1	14.2	0.2	275	400	20	1.68	15
300 MW	4	1	171	2.6	75	400	20	5.82	30
	5	1	171	2.6	175	400	20	5.82	30
	6	1	171	2.6	275	400	20	5.82	30
1,000 MW	7	1	569	8.8	75	400	20	10.62	60
	8	1	569	8.8	175	400	20	10.62	60
	9	1	569	8.8	275	400	20	10.62	60

The aerodynamic effects of surrounding structures were analyzed according to the procedures summarized in Section F.6.

It was assumed the plant would be located in flat or gently rolling terrain with a meteorological regime unfavorable to the dispersion of effluents.

Preliminary analysis indicated that for the plants a combination of unstable atmospheric conditions and relatively low wind speeds would produce the highest short-term concentrations. If such conditions occurred frequently at a given location, especially if they were combined with a high directional bias in the wind, then longer term impacts (e.g., 24 hours and annual) would tend to be high.

For Cases 1-3, preliminary analysis showed that Burbank, California, satisfied the conditions of relatively low wind speeds with moderate persistence and unstable atmospheric conditions. Upper air sounding data from Santa Monica, California, were combined with the surface station data.

For Cases 4-9, the preliminary analysis suggested slightly higher wind speeds and unstable atmospheric conditions. Oklahoma City, Oklahoma, satisfied these conditions. Although on an annual-average basis the wind speed at Oklahoma City is quite high, two features tend to offset this fact: a high annual wind-direction-frequency (22 percent from SSE) and the fact that when the wind is from this sector, atmospheric conditions tend toward the unstable. Upper air observations from Oklahoma City, Oklahoma were combined with the surface data.

Related to the choice of plant location is the selection of source-receptor distances. Preliminary analysis indicated that the model plants exert maximum impact relatively close-in. In light of the preliminary analysis, distances selected are shown in Table F-2.

F.4 RESULTS AND DISCUSSION

The maximum pollutant concentrations for the specified averaging periods for all nine cases considered are listed in Table F-3. These concentrations have been pro-rated according to their respective emission rates. The five receptor distances chosen are listed in Table F-2.

Retardation, although it occurs frequently during the year in all cases, is not the controlling factor in producing maximum concentrations. In Case No. 7, downwash occurs most of the time and does produce the maxima concentrations. The 3- and 24-hour maxima values are not representative of unique meteorological situations with the exception of Case No. 7. Numerous values in the individual maxima ranges were noted on different days at widely separated grid points at source-receptor distances similar to those reported for each case in Table F-3. This is to say then, that with the exception of Case No. 7 (downwash), concentrations similar to those shown in Table F-3 for the individual pollutants are common. It is noticeable generally that as the stack heights increased for a given plant size, the concentration decreased.

The annual-average concentration distributions displayed the expected dependence upon the wind-direction frequency distributions for each meteorological choice. Generally, concentration values similar to those shown in Table F-3 for each of the nine cases (for each individual pollutant) are confined to a sector approximately 90° in width. These concentration values were found at distances similar to those shown in Table F-3 for each individual case.

TABLE F-2[1]

	Source Receptor Distances (km.)				
Case No.	Ring 1	Ring 2	Ring 3	Ring 4	Ring 5
1	0.3	0.9	2.5	7.8	23.0
2	0.3	1.0	3.0	9.2	38.5
3	0.3	0.9	2.3	11.0	42.1
4	1.0	2.1	3.7	6.4	11.2
5	1.3	2.9	6.4	14.8	33.7
6	2.6	5.0	10.2	20.1	42.0
7	0.3	0.6	1.2	2.4	5.1
8	2.6	5.1	10.1	20.5	41.3
9	3.4	6.6	12.3	23.3	40.8

These rings may be viewed as the radii of concentric circles around the plant. Receptors are placed along each 174.5 milliradian (10°) of azimuth, thus accounting for the 180-receptor grid referred to previously.

TABLE F-3[1]

MAXIMUM POLLUTANT CONCENTRATIONS[a] ($\mu g/m^3$)

Averaging Period	Case	NO	NO_2	Distance (km)
Annual	1	0.7	<0.1	0.9
	2	0.2	<0.1	3.0
	3	<0.1	<0.1	2.3
	4	1.6	<0.1	6.4
	5	0.5	<0.1	14.8
	6	0.2	<0.1	20.01
	7	930	14	0.3[b]
	8	0.7	<0.1	20.5
	9	0.4	<0.1	23.3

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[a] Concentrations have been pro-rated according to specific emission rates.

[b] First ring, downwash.

F. 5 DESCRIPTION OF THE DISPERSION MODEL

The model used to estimate ambient concentrations in Table F-3 for the pulverized coal-fired plants was one developed by the Meteorology Laboratory, U.S. Environmental Protection Agency, Research Triangle Park, N.C. This model is designed to estimate concentrations due to sources at a single location for averaging times from one hour to one year.

This model is a Gaussian plume model using diffusion coefficients suggested by Turner.[2] Concentrations are calculated for each hour of the year, from observations of wind direction in increments of 17.45 milliradians (10 degrees), wind speed, mixing height, and atmospheric stability. The atmospheric stability is derived by the Pasquill classification method as described by Turner.[1] In the application of this model, all pollutants are considered to be non-reactive and gaseous.

Meteorological data for 1964 are used as input to the model. The reasons for this choice are: (1) data from earlier years did not have sufficient resolution in the wind direction; and (2) data after 1964 are available only for every third hour, where data for 1964 are available on an hourly basis.

Mixing height data are obtained from the twice-a-day upper air observations made at the most representative upper air station. Hourly mixing heights are estimated by the model using an objective interpolation scheme.

A feature of this model is the modification of plume behavior to account for aerodynamic effects for plants in which the design is not optimal. Another important aspect of the model is the ability to add concentrations from stacks located closely together. In this feature, no consideration is given to the physical separation between the stacks since all are assumed to be located at the same geographical point.

Calculations are made for 180 receptors (at 36 azimuths and five selectable distances from the source). The model used can consider both diurnal and seasonal variations in the source. Separate variation factors can be applied on a monthly basis to account for seasonal fluctuations and on an hourly basis to account for diurnal variations. Another feature of the model is the ability to compute frequency distributions for concentrations of any averaging period over the course of a year. Percentages of various ranges in pollutant concentrations are calculated. One final feature of the single source model is a program which can add concentrations from two plants which are not co-located but which do interact.

F.6. AERODYNAMIC-EFFECTS MODIFICATION OF THE DISPERSION MODEL

The aerodynamic-effects modification of the dispersion model was developed by the Source Receptor Analysis Branch, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, N.C.

The single source model does not address the aerodynamic complications which arise when plant design is less than ideal. These effects result from the interaction of the wind with the physical structure of the plant. Such interaction can retard, or in the extreme, prevent plume rise. The extreme case is commonly referred to as "downwash". With downwash, the effluent is brought downward into the wake of the plant, from which point it diffuses as though emitted very close to the ground. In the retardation case, some of the dispersive benefits of plume rise are lost; while in the downwash case, all of the benefits of plume rise are lost, along with most of the benefits of stack elevation. Both phenomena - but especially downwash - can seriously increase the resulting ambient air impact.

The aerodynamic-effects modification then, is an attempt to include these effects in a predictive model. Basically, it enables the model to make an hour-by-hour, stack-by-stack assessment of the extent (if any) of aerodynamic complications. The parameters used in making the assessment are wind speed, stack-gas exit velocity, stack height, stack diameter, and building height. If a particular assessment indicates no aerodynamic effect, then for that stack (for that hour) the model behaves just as the unmodified version. If there are aerodynamic effects, the modified version contains equations by which the impact of these effects on ground-level concentrations is estimated.

F.7. REFERENCES FOR APPENDIX F.

1. Unpublished Data, Source Receptor Analysis Branch, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, June 1975.

2. Turner, D. B., "Workbook of Atmospheric Dispersion Estimates", U.S. Dept. of H. E. W., PHS Publication No. 999-AP-24 (Revised 1970).